YEAR 2001

ANNUAL REPORT
OF

NorthWestern Energy, L.L.C

ELECTRIC UTILITY

TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

REVISED JULY 28, 1998

ELECTRIC ANNUAL REPORT

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Sch. 1

IDENTIFICATION

Legal Name of Respondent:	NorthWestern Energy, L.L.C. (formerly The Montana Power Company)
Name Under Which Respondent Does Business:	NorthWestern Energy, L.L.C.
Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
Person Responsible for Report:	E. J. Kindt
Telephone Number for Report Inquiries:	(406) 497-2233
Address for Correspondence Concerning Report:	40 East Broadway Butte, Montana 59701

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity.

NorthWestern Corporation
125 South Dakota Avenue
Sioux Falls, SD 57104-6403

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	NOT APPLICABLE	
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Sch. 3

OFFICERS

Title	Department Supervised	Name
President	Executive	John D. Haffey
Vice President, Human Resources and Administration	Human Resources	Pamela K. Merrell
Vice President, Treasurer and Chief Financial Officer	Treasury Services	Ellen M. Senechal
Vice President and Chief Accounting Officer	Controller Services	Ernie J. Kindt
Vice President and Chief Information Officer	Information Services	David N. Ottolino
Vice President and General Counsel	Legal Services	Michael P. Manion
Vice President, Energy Supply	Energy Supply	William A. Pascoe
Vice President, Transmission and Distribution Services	Transmission and Disbribution Services	David A. Johnson
Vice President, Regulatory Affairs	Regulatory Affairs	Patrick R. Corcoran

Sch. 4

CORPORATE STRUCTURE - 1/

Subsidiary/Company Name	Line of Business	Earnings (000)	% of Total
NORTHWESTERN ENERGY, L.L.C.			
Utility Operations		($46,677)	99.81%
Electric Utility	Electric utility		
Natural Gas Utility	Natural gas utility		
Canadian-Montana Pipe Line Corporation	Natural gas transmission		
Colstrip Community Services Company	Inactive		
Montana Power Capital 1	Financing		
MPC Natural Gas Funding Trust	Bond transition financing		
Nonutility Operations		(91)	0.19%
Montana Power Services Company	Inactive		
Discovery Energy Solutions, Inc.	Energy services consulting		
One Call Locators, Ltd.	Underground facility locating		
Colstrip Unit 4 Lease Mgmt Division	Wholesale sales of electric power *		
TOTAL		($46,768)	100.00%

1/ - This schedule is prepared as of the filing date of 4/30/02. The balance sheet is prepared as of 12/31/01, and thus discloses investments in subsidiary companies not reflected on this schedule.

* Colstrip Unit 4 Lease Management Division is an operating division of Northwestern Energy L.L.C.

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Corporate - 1/	Includes the following departments: CEO; CFO; Vice Pres. & General Counsel; Investor Services; Strategic Planning; Corp. & Shareholder Services; Business Development; Government Affairs-Federal	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	$1,897,179	67.95%	$895,040
Utility Administration Executive Department	Includes the following departments: COO; MAP; Government Affairs-State	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	1,178,906	91.36%	111,463
Human Resources	Includes the following departments: Benefits; Compensation & Labor Relations; Employment; Organizational Development; Payroll; Employee Relations; Consultant Services	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	3,891,136	78.03%	1,095,858
Financial Accounting - 2/	Includes the following departments: Vice Pres. & CFO; Chief Accounting Officer; T&D Accounting; Tax & Financial Reporting; Treasury Services; Risk Management; Internal Auditing	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	5,416,356	73.31%	1,971,460
Facilities	Includes the following departments: Facilities; Mailing Services; Records Control	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	2,709,345	88.96%	336,212
Information Services	Includes the following departments: SAP Competency Center; Infrastructure Oper.; IS Architecture; Key Accounts Representative; Security; IS Support & Services; IS Administration	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	9,331,352	86.17%	1,497,485

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Legal Services - 2/	Includes the following departments: Legal Services	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	583,797	45.92%	687,505
Corporate Communications & Advertising - 2/	Includes the following departments: Corp. Advertising; Video/Photo Services; Web Services; Corp. Communications; Community Relations; Printing Services	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	2,979,528	77.11%	884,656
TOTAL			$27,987,599	78.91%	$7,479,679

1/ - After June 30, 2001, the allocated costs include only companies sold to NorthWestern Energy.

2/ - These departments continued to do work for Touch America and Corporate through 2001, however will go with NorthWestern Energy. The split of costs does not reflect future expectations.

Sch. 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Revs.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3	Western Energy Company	Coal sales & transportation	Contract Rates	($210,381)	-0.03%	($210,381)
4		Misc. Services	Actual Costs Incurred	64,456	0.01%	64,456
5	One Call Locators	Line location services	Market Rates	1,424,423	0.20%	1,424,423
6	Tetragenics	Engineering Services	Market Rates	384,346	0.05%	384,346
7	Touch America, Inc.	Communication Services	Market Rates	870,667	0.12%	870,667
8	Entech, Inc.	Interest on notes	Interest rate used is average of	1,797,902	0.25%	1,797,902
9			short term borrowing rates &			
10			available short term investment rates.			
11			2001 Annual Average Rate = 4.8965%			
12	Discovery Energy Solutions	Energy services consulting	Market Rates	4,038	0.00%	4,038
13	Continental Energy Services, Inc.	Interest on notes	Interest rate used is average of	538,561	0.08%	538,561
14			short term borrowing rates &			
15			available short term investment rates.			
16			2001 Annual Average Rate = 4.8965%			
17	Colstrip Unit 4 -	Purchased power	Market Rates	1,064,286	0.15%	1,064,286
18	Lease Management Division					
19						
20						
21	**Total Nonutility Subsidiaries**			5,938,298	0.83%	5,938,298
22	**Total Nonutility Subsidiaries Revenues**			714,119,000		
23	**Utility Subsidiaries**					
24						
25	**Total Utility Subsidiaries**					
26	**Total Utility Subsidiaries Revenues**			7,793,000		
27	**TOTAL AFFILIATE TRANSACTIONS**			$5,938,298		$5,938,298

Sch. 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3	Western Energy Company	Sales of Electricity	Tariff Schedules	$1,686,191	0.26%	$1,686,191
4						
5	Touch America, Inc.	Sales of Gas & Electricity	Tariff Schedules	135,004	0.02%	135,004
6						
7						
8						
9	**Total Nonutility Subsidiaries**			1,821,195	0.28%	1,821,195
10	**Total Nonutility Subsidiaries Expenses**			643,134,000		
11						
12						
13	**Utility Subsidiaries**					
14	Colstrip Community Services	Project Services	Actual Costs Incurred	-	0.00%	-
15	**Total Utility Subsidiaries**			-	0.00%	-
16	**Total Utility Subsidiaries Expenses**			601,083,000		
17	**TOTAL AFFILIATE TRANSACTIONS**			$1,821,195		$1,821,195

Sch. 8	MONTANA UTILITY INCOME STATEMENT - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$478,274,646	$2,361,221	$475,913,425	$470,337,501	1.19%
3						
4	**Total Operating Revenues**	478,274,646	2,361,221	475,913,425	470,337,501	1.19%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expenses	394,301,711	$1,467,274	392,834,437	346,200,509	13.47%
9	402 Maintenance Expense	17,712,924	169,523	17,543,401	17,714,814	-0.97%
10	403 Depreciation Expense	39,869,845	367,260	39,502,585	36,078,318	9.49%
11	404-405 Amort. of Electric Plant	2,050,186		2,050,186	653,785	213.59%
12	406 Amort. of Plant Acquisition Adj.	94,914		94,914	94,939	-0.03%
13	408.1 Taxes Other Than Income Taxes	37,802,339	0	37,802,339	38,443,641	-1.67%
14	409.1 Income Taxes - Federal	(18,870,997)	69,713	(18,940,710)	3,810,127	-597.11%
15	- Other	(3,568,517)	4,584	(3,573,101)	1,396,312	-355.90%
16	410.1 Deferred Income Taxes-Dr.	27,174,446	19,249	27,155,197	10,847,576	150.33%
17	411.1 Deferred Income Taxes-Cr.	(15,981,469)		(15,981,469)	(9,641,781)	
18	411.4 Investment Tax Credit Adj.	(319,877)	(3,575)	(316,302)	(39,480)	-701.17%
19	411.6 Gain from Disposition of Property					
20	411.7 Loss from Disposition of Property					
21						
22	**Total Operating Expenses**	480,265,505	2,094,028	478,171,477	445,558,760	7.32%
23	**NET OPERATING INCOME**	($1,990,859)	$267,193	($2,258,052)	$24,778,741	-109.11%

Sch. 9	MONTANA REVENUES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Sales to Ultimate Consumers**					
3						
4	440 Residential	$133,380,492	$102,413	$133,278,079	$128,288,474	3.89%
5	442 Commercial	151,452,405	309,774	151,142,631	155,608,980	-2.87%
6	Industrial	52,961,305		52,961,305	51,201,933	3.44%
7	444 Public Street, Highway Lighting					
8	& Other Sales to Public Authorities	10,955,688	1,949,034	9,006,654	6,907,178	30.40%
9	448 Interdepartmental Sales	746,589		746,589	771,982	-3.29%
10						
11	**Total Sales to Ultimate Consumers**	349,496,479	2,361,221	347,135,258	342,778,547	1.27%
12	447 Sales for Resale	62,497,245		62,497,245	74,874,651	-16.53%
13						
14	**Total Sales of Electricity**	411,993,724	2,361,221	409,632,503	417,653,198	-1.92%
15	449.1 Provision for Rate Refunds			-	-	-
16						
17	**Total Revenue Net of Rate Refunds**	411,993,724	2,361,221	409,632,503	417,653,198	-1.92%
18						
19	**Other Operating Revenues**					
20						
21	451 Miscellaneous Service Revenue	583,343		583,343	41,728	1297.97%
22	453 Sales of Water & Water Power			0	(52,905)	100.00%
23	454 Rent From Electric Property	2,322,371		2,322,371	2,117,946	9.65%
24	456 Other Electric Revenues	63,375,208		63,375,208	50,577,534	25.30%
25						
26	**Total Other Operating Revenue**	66,280,922	-	66,280,922	52,684,303	25.81%
27	**TOTAL OPERATING REVENUE**	$478,274,646	$2,361,221	$475,913,425	$470,337,501	1.19%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1	**Power Production Expenses**					
2	**Steam Power Generation-Operation**					
3	500 Supervision & Engineering	$ -		$ -	$ -	-
4	501 Fuel	(210,381)		(210,381)	108,090	-294.64%
5	502 Steam Expenses	-		-	(15,930)	100.00%
6	503 Steam from Other Sources	-		-	40,257	-100.00%
7	505 Electric Plant	-		-	-	-
8	506 Miscellaneous Steam Power	-		-	8,274	-100.00%
9	507 Rents	-		-	4,513	-100.00%
10	**Total Operation-Steam Power Gen.**	(210,381)	-	(210,381)	145,204	-244.89%
11	**Steam Power Generation-Maintenance**					
12	510 Supervision & Engineering	-		-	-	-
13	511 Structures	-		-	-	-
14	512 Steam Boiler Plant	-		-	(508)	100.00%
15	513 Electric Plant	-		-	(426)	100.00%
16	514 Miscellaneous Steam Plant	-		-	-	-
17	**Total Maintenance-Steam Power Gen.**	-	-	-	(934)	100.00%
18	**Total Steam Power Generation**	(210,381)	-	(210,381)	144,270	-245.82%
19	**Hydro Power Generation-Operation**					
20	535 Supervision & Engineering	230,463		230,463	217,220	6.10%
21	536 Water for Power	-		-	(11,344)	100.00%
22	537 Hydraulic Expenses	875		875	18,032	-95.15%
23	538 Electric Expenses	3,762		3,762	10,527	-64.26%
24	539 Miscellaneous Hydraulic Power	83,223		83,223	62,960	32.18%
25	540 Rents	-		-	-	-
26	**Total Operation-Hydro Power Gen.**	318,323	-	318,323	297,395	7.04%
27	**Hydro Power Generation-Maintenance**					
28	541 Supervision & Engineering	249		249	-	100.00%
29	542 Structures	50,571		50,571	31,680	59.63%
30	543 Reservoirs, Dams & Waterways	187,581		187,581	36,745	410.50%
31	544 Electric Plant	43,257		43,257	4,092	957.16%
32	545 Miscellaneous Hydro Plant	7,821		7,821	3,024	158.67%
33	**Total Maintenance-Hydro Power Gen.**	289,479	-	289,479	75,540	283.21%
34	**Total Hydraulic Power Generation**	607,803	-	607,803	372,935	62.98%
35	**Other Power Generation-Operation**					
36	546 Supervision & Engineering	897	947	(50)	(93)	46.16%
37	547 Fuel	90,410	90,410	-	-	-
38	548 Generation Expenses	9,149	1,860	7,289	1,679	334.16%
39	549 Miscellaneous Other Power	6,720	7,138	(417)	65	-737.41%
40	**Total Operation-Other Power Gen.**	107,175	100,354	6,821	1,651	313.04%
41	**Other Power Generation-Maintenance**					
42	551 Supervision & Engineering	-	-	-	-	-
43	552 Structures	-	-	-	-	-
44	553 Generating & Electric Plant	20,873	21,058	(185)	(58)	-221.64%
45	554 Miscellaneous Other Power Plant	37,674	44,473	(6,799)	292	-2428.78%
46	**Total Maintenance-Other Power Gen.**	58,547	65,531	(6,984)	234	-3080.59%
47	**Total Other Power Generation**	165,722	165,886	(163)	1,886	-2767.55%
48	**Other Power Supply Expenses**					
49	555 Purchased Power	263,620,757	851,936	262,768,821	270,927,980	-3.01%
50	556 System Control & Load Dispatch	-	-	-	4,943	-100.00%
51	557 Other Expenses	63,559,958	-	63,559,958	1,033,327	6051.00%
52	**Total Other Power Supply Expenses**	327,180,715	851,936	326,328,779	271,966,251	19.99%
53	**Total Power Production Expenses**	327,743,859	1,017,822	326,726,038	272,485,342	19.91%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Expenses**					
3						
4	**Transmission-Operation**					
5	560 Supervision & Engineering	1,724,849	257	1,724,592	1,940,962	-11.15%
6	561 Load Dispatching	1,122,293	-	1,122,293	1,368,722	-18.00%
7	562 Station Expenses	193,774	-	193,774	123,649	56.71%
8	563 Overhead Lines	988,246	78,721	909,525	705,819	28.86%
9	564 Underground Lines	-	-	-	5,235	-
10	565 Transmission of Elec. by Others	(2,109,041)	-	(2,109,041)	1,865,847	-213.03%
11	566 Miscellaneous Transmission	466,033	-	466,033	456,329	2.13%
12	567 Rents	3,298,462	-	3,298,462	2,550,779	29.31%
13	**Total Operation-Transmission**	5,684,616	78,978	5,605,638	9,017,343	-37.83%
14	**Transmission-Maintenance**					
15	568 Supervision & Engineering	755,596	211	755,385	884,377	-14.59%
16	569 Structures	49,657	4,049	45,608	27,809	64.00%
17	570 Station Equipment	2,316,935	7,024	2,309,911	3,069,600	-24.75%
18	571 Overhead Lines	1,625,214	23,743	1,601,471	1,892,479	-15.38%
19	572 Underground Lines	-	-	-	549	-100.00%
20	573 Miscellaneous Transmission Plant	-	-	-	1,608	-100.00%
21	**Total Maintenance-Transmission**	4,747,402	35,026	4,712,376	5,876,423	-19.81%
22	**Total Transmission Expenses**	10,432,017	114,004	10,318,013	14,893,766	-30.72%
23						
24	**Distribution Expenses**					
25						
26	**Distribution-Operation**					
27	580 Supervision & Engineering	1,529,811	9,711	1,520,100	1,270,688	19.63%
28	581 Load Dispatching	-	-	-	-	-
29	582 Station Expenses	565,274	3,527	561,747	544,534	3.16%
30	583 Overhead Lines	2,969,603	66,718	2,902,885	4,459,867	-34.91%
31	584 Underground Lines	2,276,524	39,577	2,236,947	2,471,524	-9.49%
32	585 Street Lighting & Signal Systems	629,234	-	629,234	664,106	-5.25%
33	586 Meters	1,477,678	12,445	1,465,233	1,760,255	-16.76%
34	587 Customer Installations	1,127,840	131	1,127,709	811,737	38.93%
35	588 Miscellaneous Distribution	2,140,755	39,523	2,101,232	935,841	124.53%
36	589 Rents	101,989	-	101,989	83,594	22.01%
37	**Total Operation-Distribution**	12,818,710	171,632	12,647,078	13,002,146	-2.73%
38	**Distribution-Maintenance**					
39	590 Supervision & Engineering	764,405	-	764,405	798,844	-4.31%
40	591 Structures	126,481	2,448	124,033	67,644	83.36%
41	592 Station Equipment	872,516	14,064	858,452	1,028,890	-16.57%
42	593 Overhead Lines	5,290,727	17,266	5,273,461	6,015,528	-12.34%
43	594 Underground Lines	711,265	12,515	698,750	735,695	-5.02%
44	595 Line Transformers	681,873	2,552	679,321	614,816	10.49%
45	596 Street Lighting, Signal Systems	431,115	-	431,115	410,134	5.12%
46	597 Meters	587,566	265	587,301	460,442	27.55%
47	598 Miscellaneous Distribution Plant	-	-	-	-	-
48	**Total Maintenance-Distribution**	9,465,948	49,110	9,416,838	10,131,992	-7.06%
49	**Total Distribution Expenses**	22,284,658	220,743	22,063,915	23,134,137	-4.63%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Customer Accounts Expenses**					
3						
4	**Customer Accounts-Operation**					
5	901 Supervision			-	-	-
6	902 Meter Reading	1,179,782	1,797	1,177,985	933,134	26.24%
7	903 Customer Records & Collection	5,023,763	-	5,023,763	4,063,301	23.64%
8	904 Uncollectible Accounts	930,185	-	930,185	1,324,172	-29.75%
9	905 Miscellaneous Customer Accts.	30,767	-	30,767	170	18043.17%
10	**Total Customer Accounts Expenses**	7,164,497	1,797	7,162,700	6,320,777	13.32%
11						
12	**Customer Service & Information**					
13						
14	**Customer Service-Operation**					
15	907 Supervision	-		-	20,047	-100.00%
16	908 Customer Assistance	1,801,239		1,801,239	1,790,021	0.63%
17	909 Inform. & Instruct. Advertising	497,462		497,462	269,131	84.84%
18	910 Misc. Customer Service & Info.	(6)		(6)	400	-101.47%
19	**Total Customer Service & Info. Expense**	2,298,695	-	2,298,695	2,079,599	10.54%
20						
21	**Sales Expenses**					
22						
23	**Sales-Operation**					
24	911 Supervision	183,280		183,280	261,614	-29.94%
25	912 Demonstrating & Selling	1,104,614		1,104,614	875,768	26.13%
26	913 Advertising	26,793		26,793	389,119	-93.11%
27	916 Miscellaneous Sales	-		-	13,699	-100.00%
28	**Total Sales Expenses**	1,314,686	-	1,314,686	1,540,201	-14.64%
29						
30	**Administrative & General Expenses**					
31						
32	**Admin. & General-Operation**					
33	920 Admin. & General Salaries	19,635,224	120,208	19,515,016	13,550,784	44.01%
34	921 Office Supplies & Expenses	3,398,752	9,875	3,388,877	3,506,517	-3.35%
35	922 Admin. Expense Transferred-Cr.	(2,098,605)	(12,784)	(2,085,821)	(2,181,962)	4.41%
36	923 Outside Services Employed	2,814,571	16,450	2,798,121	5,430,442	-48.47%
37	924 Property Insurance	418,219	2,548	415,672	155,848	166.72%
38	925 Injuries & Damages	4,419,504	26,922	4,392,582	3,187,668	37.80%
39	926 Employee Pensions & Benefits	1,851,431	9,000	1,842,431	307,306	499.54%
40	927 Franchise Requirements					
41	928 Regulatory Commission Expenses	385,523		385,523	300,290	28.38%
42	407 Amortization of Property Losses	(5,903,253)		(5,903,253)	1,095,015	-639.10%
43	929 Duplicate Charges-Cr.					
44	930 Miscellaneous General Expenses	9,373,073	70,069	9,303,004	11,300,489	-17.68%
45	931 Rents	3,330,234	20,287	3,309,948	5,177,546	-36.07%
46	**Total Operation-Admin. & General**	37,624,673	262,575	37,362,098	41,829,944	-10.68%
47	**Admin. & General-Maintenance**					
48	935 General Plant	3,151,548	19,856	3,131,692	1,631,557	91.94%
49	**Total Maintenance-Admin. & General**	3,151,548	19,856	3,131,692	1,631,557	91.94%
50	**Total Admin. & General Expenses**	40,776,221	282,432	40,493,790	43,461,501	-6.83%
51	**TOTAL OPER. & MAINT. EXPENSES**	412,014,635	$1,636,797	410,377,838	$363,915,323	12.77%

Sch.11	MONTANA TAXES OTHER THAN INCOME - ELECTRIC (EXCLUDES UNIT 4)				
		Description	This Year	Last Year	% Change
1					
2		**Federal Taxes**			
3	2521xx	Social Security, Medicare and Unemployment	$4,857,068	$1,265,898	283.69%
4					
5		**Montana Taxes**			
6	252410	Real Estate & Personal Property	37,533,795	30,811,662	21.82%
7	252212	Montana Beneficial Use Tax	152,656	244,192	-37.49%
8	252213	Crow Tribe Railroad & Utility Tax	534	44,393	-98.80%
9	252218	Units 3 & 4 Transmission Property	(3,272,121)	4,406,370	-174.26%
10	252450	Electric Energy Producer's License	21,989	76,888	-71.40%
11	252450	Consumer Counsel	283,730	263,757	7.57%
12	252450	Public Service Commission	947,964	852,369	11.22%
13	252460	Wholesale Energy Transaction	1,276,481	1,308,028	-2.41%
14		Other Miscellaneous Taxes	21,099	22,266	-5.24%
15					
16		**District of Columbia Taxes**			
17	2521xx	Social Security, Medicare and Unemployment	144	216	-33.33%
18					
19		**Other**			
20		Payroll Tax Credit	(4,020,999)	(852,398)	-371.73%
21					
22	**TOTAL TAXES OTHER THAN INCOME**		$37,802,339	$38,443,641	-1.67%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES, 1/		
	Name of Recipient	Nature of Service	Total
1	Allen & Company, Inc.	Financial advisory services	$100,000
2	Alme Construction, Inc.	Gas Pipeline Construction	1,943,867
3	Anderson Tree Service	Tree trimming	483,491
4	Asplundh	Tree trimming	1,575,753
5	Bill Field Trucking, LLC	Equipment transportation	303,396
6	Buck Consultants, Inc.	Recordkeeper	125,281
7	Burns International Security	Security service	256,946
8	Cory Clarke	Engineering Services	105,995
9	Crowley, Haughey,Hanson	Legal services	293,857
10	Deloitte Consulting	Consulting	1,403,238
11	Dorsey & Whitney, LLP	Legal services	130,960
12	Express Services, Inc.	Temporary employment service	444,618
13	FX Drilling Company	Drilling Services	106,784
14	Georgeson Shareholder	Proxy statements	283,976
15	Goldman Sachs	Consulting	2,546,558
16	Gsea Montana	Advertising	391,864
17	Harp Line Constructors Co.	Line construction & maintenance	4,995,142
18	Heath Consultants, Inc.	Gas leak detection	148,892
19	Howrey & Simon	Environmental consulting	161,275
20	HR Link Group Inc.	Computer services	131,390
21	Hughes, Kellner, Sullivan & Alke	Legal services	136,206
22	IBEX Construction	Tree trimming	335,448
23	IBM Corp	Computer maintenance	1,181,633
24	Independent Inspection Co	Electric line inspection	1,052,371
25	Intergraph Public Safety	Software maintenance	125,337
26	Itron, Inc.	Hardware/software maintenance	309,774
27	Jensen's Tree Service, Inc.	Tree trimming	291,331
28	KM Construction	Contractor	115,619
29	Lewis Manufacturing & Construction	Construction	453,339
30	Mattingly Testing Services, Inc.	Inspection services	101,376
31	Merrill Communications, LLC	Printing services	757,581
32	Mike Boylan Excavating	Contractor	119,338
33	Mtn.Utility Constr.& Design	Contractor	7,665,512
34	Nat'l Ctr. For Appropriate Technology	Lab Testing	530,524
35	Natural Gas Services	Gas service work	185,544
36	Northwest Energy Efficiency	Energy serices	456,969
37	Olson Land Services	Right of way	111,415
38	Orcom Solutions	Programming & implementation	4,357,655
39	PA Consulting Services	Consulting	133,147
40	Peaker Services, Inc.	Contractor	122,421
41	PricewaterhouseCoopers	Auditing/ Consulting	837,954
42	Quality Resource & Services	Inspection services	103,303
43	Rod Tabbert Construction, Inc.	Contractor	357,495
44	Spherion Corporation	Temporary employment service	126,397
45	State Line Contractors, Inc.	Contractor	312,086
46	Sweitzer Engineering	Engineering services	140,675
47	Technology Unlimited	Computer maintenance	147,082
48	Thelen Reid & Priest, LLC	Legal services	564,455
49	Tony Laslovich	Contractor	101,278
50	Towers Perrin	Consulting/Actuary	507,458
51	XENERGY, Inc.	Contract services	1,247,988
52	Washington Infrastructure	Contract services	223,677
53	Zacha Construction, Inc.	Construction & maintenance	136,373
54			
55	**Total Payments for Services**		$39,282,047
57	1/ Due to the multiple % allocations, it is not practical to separately identify amounts charged to the electric or gas utility.		

Sch. 13

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

The Montana Power Company does not make any contributions to Political Action Committees (PACs) or candidates.

There is an employee PAC - Citizens for Responsible Government / Employees of The Montana Power Company (CRG). CRG is an organization of employees and shareholders of Montana Power and its subsidiaries. All of the money contributed by members goes to support political candidates. No company funds may be spent in support of a political candidate. Officers and local representatives of CRG donate their time. Nominal administrative costs for such things as duplicating and postage are paid by the Company. These costs are charged to shareholder expense.

Sch. 14

PENSION COSTS

Line	Description	This Year	Last Year	% Change
1	**Plan Name: Retirement Plan for Employees**			
2	**of The Montana Power Company**			
3	Defined Benefit Plan	Yes	Yes	
4	Defined Contribution Plan (See Schedule 14A)			
5	Is the Plan overfunded?	No - 3/	Yes - 2/	
6				
7	Actuarial Cost Method	Projected Unit Credit Method		
8	IRS Code			
9	Annual Contribution by Employer	0	0	
10	Accumulated Benefit Obligation - 4/	241,360,765	221,222,867	9.10%
11	Projected Benefit Obligation - 4/	229,830,140	216,129,144	6.34%
12	Fair Value of Plan Assets - 4/	191,046,243	223,920,969	-14.68%
13				
14	Discount Rate for Benefit Obligations	7.00%	7.50%	-6.67%
15	Expected Long-Term Return on Assets	9.00%	9.00%	0.00%
16				
17	Net Periodic Pension Cost:			
18	Service Cost - 4/	3,675,916	4,089,862	-10.12%
19	Interest Cost - 4/	15,612,221	14,476,386	7.85%
20	Return on Plan Assets (Expected) -4/	(17,921,050)	(20,272,561)	-11.60%
21	Net Amortization - 4/	1,900,249	(1,336,297)	-242.20%
22	Special Termination Benefit Charge - 4/	-	9,814,262	-100.00%
23	Curtailment Charge	-	-	-
24	Settlement Charge	-	-	-
25	Total Net Periodic Pension Cost	3,267,336	6,771,652	-51.75%
26				
27	Minimum Required Contribution			
28	Actual Contribution	-	-	
29	Maximum Amount Deductible	-	-	
30	Benefit Payments	15,219,835	9,942,351	53.08%
31				
32	Montana Intrastate Costs:			
33	Pension Costs	NOT APPLICABLE		
34	Pension Costs Capitalized			
35	Accumulated Pension Asset (Liability) at Year End			
36				
37	Number of Company Employees : 1/			
38	Covered by the Plan			
39	Active - 4/	1,152	1,383	-16.70%
40	Retired - 4/	1,160	881	31.67%
41	Vested Former Employees (Deferred Inactive) - 4/	873	590	47.97%
42	Total Covered by the Plan - 4/	3,185	2,854	11.60%
43	Total Not Covered by the Plan			
44				
45	1/ Obtained from The Actuarial Valuation Report of the Retirement Plan for Employees of The			
46	Montana Power Company, prepared as of January 1, 2001 and 2000 respectively.			
47				
48	2/ As of December 31, 2000, the fair value of assets was $223.9 million and the projected benefit obligation			
49	was 216.1 million. However, there was an unrecognized net gain of $25.3 million that has not been			
50	fully amortized pursuant to SFAS Statement No. 87. There is a prepaid pension cost of $10.8 million			
51	as of December 31, 2000.			
52				
53	3/ As of December 31, 2001, the fair value of assets was $191.0 million and the projected benefit obligation			
54	was 229.8 million. However, there was an unrecognized net loss of $20.6 million that has not been			
55	fully amortized pursuant to SFAS Statement No. 87. There is a pension liability of $600,000			
56	as of December 31, 2001.			

Sch. 14	PENSION COSTS			
	Description	This Year	Last Year - 3/	
1	**Plan Name: Retirement Savings Plan**			
2				
3	Defined Benefit Plan (See Schedule 14)			
4	Defined Contribution Plan	Yes	Yes	
5	Is the Plan overfunded?			
6				
7				
8	Actuarial Cost Method			
9	IRS Code			
10	Annual Contribution by Employer			
11				
12	Accumulated Benefit Obligation			
13	Projected Benefit Obligation			
14	Fair Value of Plan Assets	109,333,678	138,602,820	-21.12%
15				
16	Discount Rate for Benefit Obligations			
17	Expected Long-Term Return on Assets			
18				
19	Net Periodic Pension Cost:			
20	Service Cost			
21	Interest Cost	NOT APPLICABLE		
22	Return on Plan Assets (Actual)			
23	Net Amortization			
24	Total Net Periodic Pension Cost			
25				
26	Minimum Required Contribution			
27	Actual Contribution	NOT APPLICABLE		
28	Maximum Amount Deductible			
29	Benefit Payments			
30				
31	Montana Intrastate Costs:			
32	Pension Costs	NOT APPLICABLE		
33	Pension Costs Capitalized			
34	Accumulated Pension Asset (Liability) at Year End			
35				
36	Number of Company Employees :			
37	Covered by the Plan -- Eligible -4/	1,313	1,032	27.23%
38	Not Covered by the Plan	-	-	
39	Active -- Participating	955	1,013	-5.73%
40	Retired			
41	Vested Former Employees, Retirees and -4/	358	19	1784.21%
42	Active-Noncontributing			
43	Total Covered by the Plan -4/	1,313	1,032	27.23%
44	Total Not Covered by the Plan	0	0	
45				
46				
47				
48	4/ 2000 numbers were restated to include SAS.			

Sch 15

OTHER POST EMPLOYMENT BENEFITS (OPEBS)

	Description	This Year	Last Year	% Change
1	**General Information**	2/	1/	
2	Discount Rate for Benefit Obligations	7.00%	7.50%	-7.14%
3	Expected Long-Term Return on Assets	9.00%	9.00%	0.00%
4	Medical Cost Inflation Rate 3/	9.00%, 5.50%: 7	10.0%,5.50%: 7	
5	Actuarial Cost Method	Projected Unit Credit Actuarial		
6		Cost Method allocated from date of		
7		hire to full eligibility date.		
8	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
9	Method - Tax Advantaged (Yes or No) YES			
10	Union Employees - VEBA			
11	Non-Union Employees - 401(h)			
12	Describe Changes to the Benefit Plan: None.			
13				
14	**Total Company**			
15				
16	Accumulated Post Retirement Benefit Obligation (APBO) - 6/	$26,454,217	$20,479,046	22.59%
17	Fair Value of Plan Assets - 6/	$5,871,614	$9,706,656	-65.31%
18				
19	List the amount funded through each funding method:			
20	VEBA - 7/	$461,137	$726,947	-57.64%
21	401(h) - 7/	1,293,925	756,619	41.53%
22	Other: Cash	811,379	639,256	21.21%
23	Total Amount Funded	$2,566,441	$2,122,822	17.29%
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA - 7/	$461,137	$726,947	-57.64%
27	401(h) - 7/	1,293,925	756,619	41.53%
28	Other: Cash	811,379	639,256	21.21%
29	Total Amount Tax Deductible	$2,566,441	$2,122,822	17.29%
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost - 6/	$419,695	$429,624	-2.37%
33	Interest Cost - 6/	1,851,224	1,560,506	15.70%
34	Return on Plan Assets (Expected) - 6/	(705,817)	(817,728)	15.86%
35	Amort. Of Transition Oblig. & Regulatory Asset-6/	791,706	837,029	-5.72%
36	Amortization of Prior Service Cost - 6/	138,644	145,885	-5.22%
37	Amortization of Gains or Losses - 6/	0	(128,109)	-100.00%
38	Total Net Periodic Post Retirement Benefit Cost	$2,495,452	$2,027,207	18.76%
39	Benefit Cost Expensed - 6/	$1,976,398	$1,558,922	21.12%
40	Benefit Cost Capitalized - 6/	374,318	425,713	-13.73%
41	Benefit Cost Charged to MPC Subs & Colstrip Owners- 5/,6/	144,736	42,571	70.59%
42	Total Benefit Costs	$2,495,452	$2,027,206	18.76%
43	Benefit Payments	$811,379	$639,256	21.21%
44				
45	Number of Company Employees :			
46	Covered by the Plans			
47	Active - 6/	1,156	1,386	-19.90%
48	Retired - 6/	1,025	759	25.95%
49	Retired Spouse/Dependents	44	28	36.36%
50	Total Covered by the Plans	2,225	2,173	2.34%
51	Total Not Covered by the Plans	210	264	-25.71%
52	1/ Obtained from MPC's 2000 FASB 106 Valuation. Assumptions and data are as of December 31, 2000.			
53	2/ Obtained from MPC's 2001 FASB 106 Valuation. Assumptions and data are as of December 31, 2001.			
54	3/ First Year, Ultimate, Years to Reach Ultimate.			

Sch 15A	OTHER POST EMPLOYMENT BENEFITS (OPEBS)			
	Description	This Year	Last Year	% Change
1	**General Information**	4/	4/	
2	Discount Rate for Benefit Obligations			
3	Expected Long-Term Return on Assets			
4	Medical Cost Inflation Rate 3/			
5	Actuarial Cost Method			
6				
7				
8	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
9	Method - Tax Advantaged (Yes or No) YES			
10	Union Employees - VEBA			
11	Non-Union Employees - 401(h)			
12	Describe Changes to the Benefit Plan: None.			
13				
14	**Montana**	4/	4/	
15				
16	Accumulated Post Retirement Benefit Obligation (APBO)			
17	Fair Value of Plan Assets			
18				
19	List the amount funded through each funding method:			
20	VEBA			
21	401(h)			
22	Other: Cash			
23	Total Amount Funded			
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA			
27	401(h)			
28	Other: Cash			
29	Total Amount Tax Deductible			
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost			
33	Interest Cost			
34	Return on Plan Assets - Estimated			
35	Amort. of Transition Oblig. & Regulatory Asset			
36	Amortization of Gains or Losses			
37	Total Net Periodic Post Retirement Benefit Cost			
38	Benefit Cost Expensed			
39	Benefit Cost Capitalized			
40	Benefit Cost Charged to MPC Subs & Colstrip Owners			
41	Total Benefit Costs			
42	Benefit Payments			
43				
44	Number of Company Employees :			
45	Covered by the Plans			
46	Active			
47	Retired			
48	Retired Spouse/Dependents			
49	Total Covered by the Plans			
50	Total Not Covered by the Plans			
51	4/ Substantially all of the amounts are subject to the PSC jurisdiction. Actual amounts that will be			
52	expensed, will reflect reductions for amounts billed to others or allocated to Yellowstone National Park.			
53	5/ Due to the sale of generating assets, there is no longer billing to Colstrip owners from 2000 forward.			
54	6/ 2000 restatements.			
55	7/ 2001 Trust funding was made on January 11, 2002.			

Sch. 16 TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Name/Title	Base Salary 1/	Other Comp. 2/	Total Comp.	Total Comp. Last Year	% Change
R. P. Gannon Chairman of the Board and Chief Executive Officer	$487,981	$12,019 <A 6,800 <B 100,000 <C 1,078 <D 2,239 <E 145 <F 780 <G 682 <H	$611,724	$764,340	-20%
J. D. Haffey Executive Vice President and Chief Operating Officer	188,896	21,576 <A 6,800 <B 80,523 <C 920 <E 380 <F 3,948 <G	303,043	327,701	-8%
J. P. Pederson Vice Chairman and Chief Financial Officer	250,000	6,800 <B 34,375 <C 617 <E	291,792	359,473	-19%
D. A. Johnson Vice President, Distribution Services	173,935	6,800 <B 52,729 <C 351 <E 249 <F	234,064	231,201	1%
M. E. Zimmerman Vice President and General Counsel	182,231	6,800 <B 26,013 <C 237 <D 1,558 <F 150 <H	$216,989	$242,018	-10%
W. A. Pascoe Vice President, Transmission Services	CONFIDENTIAL INFORMATION NOT REQUIRED FOR GENERAL DISTRIBUTION				
D. J. Sullivan Chief Information Officer					

Sch. 16

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Name/Title	Base Salary 1/	Other Comp. 2/	Total Comp.	Total Comp. Last Year	% Change
P. K. Merrell Vice President, Human Resources	CONFIDENTIAL INFORMATION NOT REQUIRED FOR GENERAL DISTRIBUTION				
M. P. Manion Legal Services					
E. M. Senechal Treasurer					

1/ Salary includes the employees' annual base federally taxable earnings, pretax contributions to the Company's Deferred Savings and Employee Stock Ownership (401(K)) Plan, pretax Section 125 flexible spending account contributions, pretax medical premium contributions, and, in some cases, tax deferred Executive Benefit Restoration Plan contributions.

2/ All Other Compensation for named employees consists of the following:

A> Vacation time sold back to the Company. The vacation sellback program is available to all employees.

B> The value of the Company's matching contribution of stock (through 10/31/01) and cash (11/1/01 - 12/31/01) made to the employee's account under the Retirement Savings Plan (401(K) plan) sponsored by the Company.

C> Incentive Compensation Plan which were earned under the 2000 EVA Bonus Plan.

D> Taxable fringe benefit.

E> Imputed taxable income on Company-paid life insurance premiums.

F> Company-paid physical examinations.

G> Personal use of company vehicles.

H> Spot cash bonus awards.

Sch. 17

COMPENSATION OF TOP FIVE CORPORATE EMPLOYEES - SEC INFORMATION

Name/Title	Base Salary 1/	Other Comp. 2/	Total Comp.	Total Comp. Last Year	% Change
R. P. Gannon	$487,981	$12,019 <A			
Chairman of the Board		6,800 <B			
and Chief Executive		100,000 <C			
Officer		1,078 <D			
		2,239 <E			
		145 <F			
		780 <G			
		682 <H			
			$611,724	$764,340	-20%
J. D. Haffey	188,896	21,576 <A			
Executive Vice President and		6,800 <B			
Chief Operating Officer		80,523 <C			
		920 <E			
		380 <F			
		3,948 <G			
			303,043	327,701	-8%
J. P. Pederson	250,000	6,800 <B			
Vice Chairman and		34,375 <C			
Chief Financial Officer		617 <E			
			291,792	359,473	-19%
D. A. Johnson	173,935	6,800 <B			
Vice President,		52,729 <C			
Distribution Services		351 <E			
		249 <F			
			234,064	231,201	1%
M. E. Zimmerman	182,231	6,800 <B			
Vice President and		26,013 <C			
General Counsel		237 <D			
		1,558 <F			
		150 <H			
			$216,989	$242,018	-10%

1/ Salary includes the employees' annual base federally taxable earnings, pretax contributions to the Company's Deferred Savings and Employee Stock Ownership (401(K)) Plan, pretax Section 125 flexible spending account contributions, pretax medical premium contributions, and, in some cases, tax deferred Executive Benefit Restoration Plan contributions.

2/ All Other Compensation for named employees consists of the following:

A> Vacation time sold back to the Company. The vacation sellback program is available to all employees.

B> The value of the Company's matching contribution of stock (through 10/31/01) and cash (11/1/01 - 12/31/01) made to the employee's account under the Retirement Savings Plan (401(K) plan) sponsored by the Company.

C> Incentive Compensation Plan which were earned under the 2000 EVA Bonus Plan.

D> Taxable fringe benefit.

E> Imputed taxable income on Company-paid life insurance premiums.

F> Company-paid physical examinations.

G> Personal use of company vehicles.

H> Spot cash bonus awards.

Sch. 18

BALANCE SHEET 1/

	Account Title	This Year	Last Year	% Change
1	**Assets and Other Debits**			
2	**Utility Plant**			
3	101 Plant in Service 2/	$1,545,871,892	$1,221,842,478	26.52%
4	105 Plant Held for Future Use	8,984	8,984	0.00%
5	107 Construction Work in Progress	10,447,595	1,805,954	478.51%
6	108 Accumulated Depreciation Reserve	(539,286,806)	(493,655,655)	-9.24%
7	111 Accumulated Amortization & Depletion Reserves	(12,169,750)	(9,683,037)	-25.68%
8	114 Electric Plant Acquisition Adjustments	3,106,285	3,106,285	0.00%
9	115 Accumulated Amortization-Electric Plant Acq. Adj.	(2,346,971)	(2,252,057)	-4.21%
10	117 Gas Stored Underground-Noncurrent	42,397,528	40,710,265	4.14%
11	**Total Utility Plant**	1,048,028,757	761,883,217	37.56%
12	**Other Property and Investments**			
13	121 Nonutility Property	2,061,961	2,780,825	-25.85%
14	122 Accumulated Depr. & Amort.-Nonutililty Property	(87,849)	(69,747)	-25.95%
15	123.1 Investments in Subsidiary Companies	807,438,353	759,190,205	6.36%
16	123 Investments in Colstrip Unit 4 & YNP	44,835,353	46,158,027	-2.87%
17	124 Other Investments	21,447,804	21,162,587	1.35%
18	128 Miscellaneous Special Funds	1,429,900	1,393,095	2.64%
19	**Total Other Property & Investments**	877,125,522	830,614,992	5.60%
20	**Current and Accrued Assets**			
21	131 Cash	(3,630,377)	(4,330,121)	16.16%
22	135 Working Funds	52,365	89,047	-41.19%
23	136 Temporary Cash Investments	7,000,000	-	
24	141 Notes Receivable	181,476	254,123	-28.59%
25	142 Customer Accounts Receivable	43,310,904	75,778,151	-42.85%
26	143 Other Accounts Receivable	5,093,295	22,238,445	-77.10%
27	144 Accumulated Provision for Uncollectible Accounts	(1,223,900)	(1,163,900)	-5.16%
28	145 Notes Receivable-Associated Companies	-	60,980,872	-100.00%
29	146 Accounts Receivable-Associated Companies	34,656,551	125,321,575	-72.35%
30	151 Fuel Stock	-	151,070	-100.00%
31	154 Plant Materials and Operating Supplies	9,111,610	10,238,825	-11.01%
32	165 Prepayments	16,272,659	11,574,145	40.59%
33	171 Interest and Dividends Receivable	12,114	2,380,228	-99.49%
34	172 Rents Receivable	97,443	266,113	-63.38%
35	173 Accrued Utility Revenues	22,696,131	27,744,975	-18.20%
36	174 Miscellaneous Current & Accrued Assets	127,893	64,019	99.77%
36	**Total Current & Accrued Assets**	133,758,164	331,587,567	-59.66%
37	**Deferred Debits**			
38	181 Unamortized Debt Expense	3,763,307	3,353,218	12.23%
39	182 Regulatory Assets	209,378,179	206,288,584	1.50%
40	183 Preliminary Survey and Investigation Charges	625,340	625,340	0.00%
41	184 Clearing Accounts	(78)	(27,020)	99.71%
42	185 Temporary Facilities	78	(12,238)	100.63%
43	186 Miscellaneous Deferred Debits	37,476,788	14,500,996	158.44%
44	189 Unamortized Loss on Reacquired Debt	3,607,678	3,914,566	-7.84%
45	190 Accumulated Deferred Income Taxes	175,932,149	170,007,486	3.48%
46	191 Unrecovered Purchased Gas Costs	(6,659,440)	14,414,108	-146.20%
47	**Total Deferred Debits**	424,124,001	413,065,040	2.68%
48	**TOTAL ASSETS and OTHER DEBITS**	$2,483,036,444	$2,337,150,816	6.24%

Sch. 18 cont.	BALANCE SHEET 1/			
	Account Title	This Year	Last Year	% Change
1	**Liabilities and Other Credits**			
2	**Proprietary Capital**			
3	201 Common Stock Issued	$706,100,642	$705,656,783	0.06%
4	204 Preferred Stock Issued	58,063,500	58,063,500	0.00%
5	207 Premium on capital stock	-	-	
6	211 Miscellaneous Paid-In Capital	2,347,399	2,391,602	-1.85%
7	213 Discount on Capital Stock	(815,700)	(815,700)	0.00%
8	214 Capital Stock Expense	(93,888)	(93,889)	0.00%
9	215 Appropriated Retained Earnings	6,238,312	6,238,312	0.00%
10	216 Unappropriated Retained Earnings	610,411,500	595,587,557	2.49%
11	217 Reacquired capital stock	(205,656,384)	(205,656,384)	0.00%
12	**Total Proprietary Capital**	1,176,595,381	1,161,371,781	1.31%
13	**Long Term Debt**			
14	221 Bonds	327,402,000	177,402,000	84.55%
15	224 Other Long Term Debt	145,666,000	209,197,000	-30.37%
16	226 Unamortized Discount on Long Term Debt-Debit	(3,210,502)	(2,443,514)	-31.39%
17	**Total Long Term Debt**	469,857,498	384,155,486	22.31%
18	**Other Noncurrent Liabilities**			
19	227 Obligations Under Capital Leases-Noncurrent	-	4,166	-100.00%
20	228.1 Accumulated Provision for Property Insurance	410,424	939,516	-56.32%
21	228.2 Accumulated Provision for Injuries and Damages	3,314,632	2,790,548	18.78%
22	228.3 Accumulated Provision for Pensions and Benefits	8,169,359	6,736,462	21.27%
23	228.4 Accumulated Miscellaneous Operating Provisions	5,155,912	7,350,000	-29.85%
24	**Total Other Noncurrent Liabilities**	17,050,327	17,820,692	-4.32%
25	**Current and Accrued Liabilities**			
25	231 Notes Payable	-	75,000,000	-100.00%
26	232 Accounts Payable	23,509,160	70,843,169	-66.82%
27	233 Notes Payable to Associated Companies	24,810,881	49,372,117	-49.75%
28	234 Accounts Payable to Associated Companies	75,088,194	157,968,250	-52.47%
29	235 Customer Deposits	1,398,414	849,654	64.59%
30	236 Taxes Accrued	(623,365)	27,568,964	-102.26%
31	237 Interest Accrued	6,572,178	4,821,957	36.30%
32	238 Dividends Declared	776,264	1,456,066	-46.69%
33	241 Tax Collections Payable	(142,569)	(304,174)	53.13%
34	242 Miscellaneous Current and Accrued Liabilities	31,537,543	30,465,232	3.52%
35	243 Obligations Under Capital Leases-Current	10,962	22,542	-51.37%
36	**Total Current and Accrued Liabilities**	162,937,662	418,063,777	-61.03%
37	**Deferred Credits**			
38	252 Customer Advances for Construction	21,030,639	20,944,582	0.41%
39	253 Other Deferred Credits	58,246,304	6,685,685	771.21%
40	254 Regulatory Liabilities	329,414,254	60,280,578	446.47%
41	255 Accumulated Deferred Investment Tax Credits	12,718,195	13,162,867	-3.38%
42	257 Unamortized Gain on Reacquired Debt	13,149	22,360	-41.20%
43	281-283 Accumulated Deferred Income Taxes	235,173,035	254,643,008	-7.65%
44	**Total Deferred Credits**	656,595,576	355,739,080	84.57%
45	**TOTAL LIABILITIES and OTHER CREDITS**	$2,483,036,444	$2,337,150,816	6.24%
46	1/ Includes CMP and Montana Power Capital I; excludes Colstrip Unit 4 and Yellowstone National Park.			
47				
48	2/ The 2000 plant in service balance included a credit amount of approximately $249,000,000 in account			
49	102. This represented the excess of proceeds over the book value of electric generating assets sold			
50	in 1999. This credit was moved to regulatory liabilities in 2001 in accordance with a FERC			
49	order in Docket No. AC00-70-000.			

NOTES TO THE FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

- **BASIS OF ACCOUNTING**

Our accounting policies conform to generally accepted accounting principles. With respect to our utility operations, these policies are in accordance with the accounting requirements and ratemaking practices of applicable regulatory authorities.

- **USE OF ESTIMATES**

Preparing financial statements requires the use of estimates based on available information. Actual results may differ from our accounting estimates as new events occur or we obtain additional information.

- **FINANCIAL STATEMENT PRESENTATION**

The financial statements are presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. This report differs from generally accepted accounting principles due to FERC requiring the reflection of subsidiaries on the equity method of accounting, which differs from Statement of Financial Accounting Standards (SFAS) No. 94, "Consolidation of All Majority-Owned Subsidiaries. SFAS No. 94 requires that all majority-owned subsidiaries be consolidated. The other differences are comparative statements of retained earnings and cash flows and net income per share are not presented.

- **CASH AND CASH EQUIVALENTS AND TEMPORARY CASH INVESTMENTS**

We consider all liquid investments with original maturities of three months or less to be cash equivalents, and investments with original maturities over three months and up to one year as temporary investments. All temporary investments at December 31, 2001, had original maturities of three months or less.

❑ PROPERTY, PLANT, AND EQUIPMENT

The following table provides year-end balances of the major classifications of our property, plant, and equipment, which we record at cost:

	December 31, 2001	December 31, 2000
	(Thousands of Dollars)	
UTILITY PLANT:		
Electric:		
Generation (including our share of jointly owned)	$ 9,488	$ (238,431)
Transmission	397,219	395,218
Distribution	623,054	597,871
Other	125,305	91,163
Natural Gas:		
Storage	72,617	71,659
Transmission	173,750	167,416
Distribution	154,450	151,039
Other	45,949	31,539
Total plant	$1,601,832	$1,267,474

We capitalize the cost of plant additions and replacements, including an allowance for funds used during construction (AFUDC) of utility plant. We determine the rate used to compute AFUDC in accordance with a formula established by FERC. This rate averaged 6.1 percent for 2001 and 8.6 percent for 2000.

We charge costs of utility depreciable units of property retired, plus costs of removal less salvage, to accumulated depreciation and recognize no gain or loss. We charge maintenance and repairs of plant and property, as well as replacements and renewals of items determined to be less than established units of plant, to operating expenses.

Included in the plant classifications are utility plant under construction in the amounts of $10,448,000 and $1,806,000 for 2001 and 2000, respectively.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of properties determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 3.4 percent for 2001 and 3.5 percent for 2000.

❑ REVENUE AND EXPENSE RECOGNITION

We record operating revenues monthly on the basis of consumption or services rendered. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to customers but not yet billed at month-end.

The Emerging Issues Task Force (EITF) Issue No. 98-10 requires that energy contracts entered into under "trading activities" be marked to market with the gains or losses shown net in the income statement. EITF 98-10 became effective for fiscal years beginning after December 15, 1998. We adopted

EITF 98-10 as of January 1, 1999, and accordingly mark to market energy contracts that qualify as "trading activities." The cumulative effect of adopting EITF 98-10 had no material effect on our financial position, results of operations, or cash flows.

- **REGULATORY ASSETS AND LIABILITIES**

For our regulated operations, we follow SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Pursuant to this pronouncement, certain expenses and credits, normally reflected in income as incurred, are recognized when included in rates and recovered from or refunded to the customers. The significant regulatory assets and liabilities we have recorded are discussed below.

Regulatory assets and liabilities related to electric supply were included in our filing with the Montana Public Service Commission (PSC) to address stranded costs. These amounts offset the gain realized on the sale of the electric generating assets in the determination of net stranded costs. Amortization of these items stopped in February 2000 when they were removed from rates. The electric supply related regulatory assets and liabilities were removed from the balance sheet in February of 2002 as a result of the PSC order in our Tier II rate filing. For further information on the effects of the sale of our electric generating assets and our Tier II filing, see Note 2, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets."

In Docket No. AC00-70-000, FERC allowed us to move the net proceeds from the electric generating asset sale from account 102, "Electric Plant Purchased or Sold," to account 254, "Other Regulatory Liabilities." This transfer was done in February 2001 and at December 31, 2001 the liability balance was $257,519,000.

In the ratemaking process, tax costs and benefits related to certain temporary differences are recovered in rates on an as paid or "flow-through" basis. SFAS No. 109, "Accounting for Income Taxes," requires that tax assets and liabilities be reflected on the balance sheet on an accrual basis. This timing difference requires that we recognize a regulatory asset for taxes accrued but not yet recovered in rates. That regulatory asset was $61,375,000 and $88,822,000 as of December 31, 2001 and 2000, respectively.

In August 1985, the Montana Public Service Commission (PSC) issued an order allowing us to recover deferred carrying charges and depreciation expenses over the remaining life of Colstrip Unit 3. These recoveries compensated us for unrecovered costs of our investment for the period from January 10, 1984, to August 29, 1985, when we placed the plant in service. We were amortizing this asset to expense, and recovering in rates, $1,831,000 per year. At December 31, 2001 and 2000, the unamortized amount was $38,337,000.

We also include costs related to our Demand Side Management (DSM) programs in other regulatory assets. This amount was $27,956,000 for both 2001 and 2000. These costs were in rate base and we were amortizing them to income over a 10-year period.

We recorded a regulatory liability of $32,549,000 in connection with the sale of our unregulated oil and natural gas operations on October 31, 2000. The liability represents the portion of the proceeds from the sale attributable to properties previously in the natural gas utility's rate base. Based on gas stipulation agreements addressing the removal of natural gas production properties from regulation, we had agreed to share this amount with our natural gas utility ratepayers and are amortizing this amount over a one-year period beginning in February 2001. In September 2001, after all testimony addressing the amount of sharing had been filed with the PSC, we reached an agreement with intervening parties to increase the amount of the credit to approximately $56,300,000. This $23,751,000 increase, along with approximately $5,540,000 in interest from the date of sale, was added to the liability and will be credited to customers' bills over a two-year period beginning in January 2002. At December 31, 2001 and 2000, the balance in this account was $33,426,000 and $32,549,000, respectively.

Certain other amounts represent items that we are amortizing currently or are subject to future regulatory confirmation.

Changes in regulation or changes in the competitive environment could result in our not meeting the criteria of SFAS No. 71. If we were to discontinue application of SFAS No. 71 for some or all of our regulated operations, we would have to eliminate the related regulatory assets and liabilities from the balance sheet. We would include the associated expenses and credits in income in the period when the discontinuation occurred, unless recovery of those costs was provided through rates charged to those customers in portions of the business that were to remain regulated.

❑ STORM DAMAGE AND ENVIRONMENTAL REMEDIATION COSTS

When losses from costs of storm damage and environmental remediation obligations for our utility operations are probable and reasonably estimable, we charge these costs against established, approved operating reserves.

❑ INCOME TAXES

We defer income taxes to provide for the temporary differences between the financial reporting basis and the tax basis of our assets and liabilities. For further information on income taxes, see "Regulatory Assets and Liabilities" mentioned above and Note 3, "Income Tax Expense."

❑ ASSET IMPAIRMENT

In accordance with SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of," we periodically review long-lived assets for impairment whenever events or changes in circumstances indicate that we may not recover the carrying amount of an asset.

❑ COMPREHENSIVE INCOME

Comprehensive income consists of net income (loss) and other comprehensive income (loss). For the years ended December 31, 2001 and 2000, other comprehensive loss consisted of marked to market adjustments related to derivative financial instruments, loss on a benefit restoration plan, and foreign currency translation adjustments of the assets and liabilities of Canadian-Montana Pipe Line Corporation (CMP). These amounted to a decrease to retained earnings of approximately $410,000 and $1,695,000, respectively.

The accumulated balance of other comprehensive income (loss) at December 31, 2001 and 2000, was $2,086,000 and $1,676,000, respectively.

❑ DERIVATIVE FINANCIAL INSTRUMENTS

Electric Swap Agreements

Long-term power supply agreements, primarily one with a large industrial customer, exposed us to commodity price risk. We were exposed to this risk to the extent that a portion of the electric energy we were required to sell to our industrial customers at fixed rates was purchased at prices indexed to a wholesale electric market, which can be higher than the fixed sales rate that we received pursuant to our power supply agreements. We mitigated our exposure to losses on these agreements with financial derivative instruments called "price swaps" and offsetting electric energy purchase and sales agreements.

Since June 1998, we have had a price swap agreement with one of our industrial customers that converts 43 MWs of the Mid-Columbia (Mid-C) index price of our supply agreement with that customer to a fixed price through May 2001. In fiscal year 2000, we also entered into another price swap with a counterparty that effectively hedged 35 MWs of the anticipated market-based purchases to supply that agreement through March 2001.

Prior to fiscal year 2001, in accordance with the provisions of SFAS No. 80, "Accounting for Futures Contracts," we recognized gains and losses from the financial swaps in the same period in which we recognized the sales and related purchases under that agreement. For fiscal year 2000, we recognized a net gain of approximately $16,000,000 from these financial swaps and losses of approximately $32,200,000 from supplying large industrial customers. For more specific information about the commodity price risk that we face as a result of our long-term power supply agreements, see Note 10, "Contingencies," in the "Long-Term Power Supply Agreements" section.

An estimate of the fair market value of the swaps based on the Mid-C forward prices as of December 29, 2000 aggregated a gain of approximately $21,800,000 as of December 31, 2000, which would offset approximately 40 percent of the expected losses on the above power supply agreements.

Effective January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Transactions and Hedging Activities." These pronouncements expand the definition of a derivative and require that all derivative instruments be recorded as assets or liabilities on an entity's balance sheet at fair value. Accounting for gains and losses resulting from changes in the fair value of those derivatives is dependent on the use of the derivative and whether it qualifies for hedge accounting.

At January 1, 2001, we had price swap agreements that hedged our exposure to variability in expected cash flows attributable to commodity price risk. Specifically, long-term power supply agreements, primarily one with a large industrial customer, expose us to that risk, to the extent that a portion of the electric energy we are required to sell to our industrial customers at fixed rates is purchased at prices indexed to the Mid-Columbia (Mid-C) wholesale electric market, which can be higher than the fixed sales rates. Another agreement to sell 1,760,000 dekatherms of natural gas storage at a monthly price based on the Alberta Energy Company "C" Hub (AECO-C) index, from October 2000 to March 2001, exposed us to adverse fluctuation in that market price index. In accordance with the provisions of SFAS No. 133, we marked to market at January 1, 2001 our price swap agreements hedging these forecasted electric energy and natural gas sales, with a corresponding credit entry to "Other comprehensive income" for approximately $11,300,000 after income taxes. That entry represented our cumulative transition adjustment in adopting SFAS No. 133, and is reflected in the Combined Statement of Other Equity in 2001.

For the first seven months of 2001, we were exposed to commodity price risk because a portion of the electric energy we were required to sell at fixed rates to industrial customers was purchased at prices indexed to a wholesale electric market, which could be and was higher than the fixed sales rate. We used derivative financial instruments called "price swaps" and offsetting electric energy purchase and sales agreements to hedge our exposure to losses on these power supply agreements with large industrial customers.

For the year ended December 31, 2001, the electric energy sales resulted in an after-tax loss of $25,300,000, and the price swaps hedging those sales in an after-tax gain of approximately $7,200,000. At December 31, 2001, we did not have agreements to purchase electric energy for sales to industrial customers or power marketers, nor did we have financial derivative agreements to hedge such transactions.

Natural Gas Utility Swaps

By drilling wells and adding compression at our Cobb storage reservoir, we were able to sell natural gas that had been held in reserve to provide firm storage deliverability to our customers. We therefore contracted to sell, from October 2000 through March 2001, 1,760,000 dekatherms from that reservoir at a monthly price based on the Alberta Energy Company "C" Hub (AECO-C) index. To reduce our exposure to fluctuations of the market index price, we entered into a swap agreement with a counterparty that effectively converted that index price to a fixed price for 903,000 dekatherms associated with these sales from December 2000 through February 2001.

For December 2000, we recognized a loss of approximately $300,000 on the swap and a profit of approximately $1,200,000 on the sale of the Cobb storage natural gas. Based on the AECO-C forward prices at December 29, 2000, we estimated a loss of approximately $3,000,000 on the swap to offset profits of $4,900,000 on the sale through February 2001. We deferred the net profit of these transactions in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," and will recognize this amount in income as amounts are reflected in rates.

- **FAIR VALUE OF FINANCIAL INSTRUMENTS**

	2001		2000	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
	(Thousands of Dollars)			
ASSETS:				
Investments	$ 21,448	$ 21,448	$ 21,127	$ 21,127
LIABILITIES:				
Long-term debt	$ 469,857	$ 458,861	$ 384,155	$ 381,654

The following methods and assumptions were used to estimate fair value:

- Investments - The carrying value of most of the investments approximates fair value as they have short maturities or the carrying value equals their cash surrender value. The investments consist mainly of the cash value of insurance policies associated with an unfunded, nonqualified benefit plan for senior management, executives, and directors.

- Long-term debt - The fair value was estimated using quoted market rates for the same or similar instruments. Where quotes were not available, fair value was estimated by discounting expected future cash flows using year-end incremental borrowing rates.

NOTE 2 - DEREGULATION, REGULATORY MATTERS, AND 1999 SALE OF ELECTRIC GENERATING ASSETS

❑ DEREGULATION

The electric and natural gas utility businesses in Montana are transitioning to a competitive market in which commodity energy products and related services are sold directly to wholesale and retail customers.

Electric

Montana's Electric Utility Industry Restructuring and Customer Choice Act (Electric Act), passed in 1997, provides that all customers will be able to choose their electric supplier by July 1, 2002, with our electric utility acting as default supplier through the transition period. As default supplier, we are obligated to continue to supply electric energy to customers in our service territory who have not chosen, or have not had an opportunity to choose, other power suppliers during the transition period. This obligation requires us to develop an energy supply portfolio to meet these customers' electric needs. Buyback contracts with PPL Montana, LLC (PPL Montana), the purchaser of our former electric generating assets, allow us to purchase power necessary to serve these customers through the transition period ending June 30, 2002.

In its 2001 session, the Montana Legislature passed House Bill 474 (HB 474), which extends the transition period through June 30, 2007. This law also provides for the use of a cost-recovery mechanism that ensures all prudently incurred electric energy supply costs of the default supplier are fully recoverable in rates. Initiative 117, which if passed would repeal HB 474, has been approved for inclusion on the November 2002 ballot in Montana. In the event that HB 474 is repealed, Montana Law would continue the transition period through at least June 30, 2007, and provide full cost recovery.

On October 29, 2001, Montana Power filed with the PSC the default supply portfolio, containing a mix of long and short-term contracts that were negotiated in order to provide electricity to default supply customers. This filing seeks approval of the default supply portfolio contracts and establishment of default supply rates for customers who have not chosen alternative suppliers by July 1, 2002. We expect that the costs of the supply portfolio and a competitive transition charge for out-of-market QF costs, as discussed below, will increase residential electric rates by approximately 20 percent beginning July 1, 2002. As discussed below, this will be offset for one year by a credit that reduces the increase to 12.8 percent. If the PSC does not approve the default supply portfolio, we may be required to seek alternative sources of supply. While we believe that we have met our default supply obligations prudently, the PSC could also disallow the recovery of costs incurred in entering into the default supply portfolio if a determination is made that the contracts were not entered into prudently.

On that same day, Montana Power submitted an updated Tier II filing with the PSC, addressing the recovery of transition costs of generation assets and other power-purchase contracts, generation-related regulatory asset transition costs, and transition costs associated with the out-of-market QF power-purchase contract costs. Previously, Montana Power initiated litigation in Montana District Court in Butte to address the ability to use tracking mechanisms to ensure fair and accurate recovery of these costs. Although the District Court ruled that the PSC must allow tracking mechanisms in the transition plan proposal, the Montana Supreme Court reversed this decision on appeal by the PSC and the Large Customer Group, which consists of various large industrial customers. Together with NorthWestern, the Montana Consumer Counsel, Commercial Energy and the Large Customer Group, on December 28, 2001, Montana Power submitted to the PSC an agreed upon stipulation settling the transition cost recovery in the Tier II filing and approving the sale to NorthWestern. The stipulation calls for Montana Power, through Touch America, and NorthWestern to establish a $30,000,000 account that will be used to provide a credit for our electric distribution customers. The credit will be provided over a one year period to customers on a per kilowatt-hour (Kwh) basis beginning on July 1, 2002, when our current below market energy supply contract expires. The credit will reduce a projected 20 percent increase in electric rates at that time to about 12.8 percent for the next 12 months. The stipulation also states that customers shall have no obligation to pay any transition costs accrued under or relating to the accounting orders issued by the PSC. These accrued transition costs through December 31, 2001, amount to $23,000,000. Another portion of the stipulation establishes the net present value (NPV) of out-of-market QF transition costs at $244,711,065, a reduction of $60,000,000, from the NPV presented in our October 29, 2001 filing. The effects of the stipulation were contingent upon the approval of the PSC and the consummation of the sale. On January 31, 2002, the PSC unanimously approved the stipulation.

Natural Gas

Montana's Natural Gas Utility Restructuring and Customer Choice Act, also passed in 1997, provides that a natural gas utility may voluntarily offer its customers choice of natural gas suppliers and provide open access. We have opened access on our gas transmission and distribution systems, and all of our natural gas customers have the opportunity of gas supply choice.

❑ **REGULATORY MATTERS**

The PSC regulates our transmission and distribution services and approves the rates that we charge for these services, while FERC regulates our transmission services and our remaining generation operations. Current regulatory issues are discussed below.

Sale of the Utility Business

Together with NorthWestern, Montana Power filed joint applications with FERC on December 20, 2000, and with the PSC on January 11, 2001, seeking approval of the sale of the utility business formerly held by Montana Power to NorthWestern. FERC issued its approval on February 20, 2001. The PSC issued an order in June 2001 denying the joint application, claiming that insufficient information had been provided for it to fully evaluate whether the transaction is in the public interest. The PSC itemized additional information that must be provided before processing of the case could continue. Montana Power re-filed the joint application with the PSC in August 2001 and the PSC established a procedural schedule setting January 31, 2002 as the date for issuance of an order. As discussed above, together with NorthWestern, the Montana Consumer Counsel, Commercial Energy, and the Large Customer Group, on December 28, 2001, Montana Power submitted to the PSC an agreed-upon stipulation relating to the Tier II filing and the approval of the sale to NorthWestern Corporation. On January 31, 2002, the PSC unanimously approved the stipulation. The stipulation and the following PSC Order recognized that NorthWestern sufficiently demonstrated its capability to assume responsibility for the utility operations and will continue to be fit, willing and able provider of adequate service and facilities at just and reasonable rates. The utility business was sold to NorthWestern on February 15, 2002. For accounting convenience, due to the burden of a mid-month closing, both parties agreed to an effective date for the sale as of the opening of business on February 1, 2002.

Pending Transmission Asset Sale

In accordance with our Asset Purchase Agreement with PPL Montana, we expect to sell our portion of the 500-kilovolt transmission system associated with Colstrip Units 1, 2, and 3 for $97,100,000, subject to the receipt of required regulatory approvals. We expect this transaction to close in 2002.

PSC

Electric Rates

In August 2000, Montana Power filed a combined request for increased electric and natural gas rates with the PSC, requesting increased annual electric transmission and distribution revenues of approximately $38,500,000, with a proposed interim annual increase of approximately $24,900,000. On November 28, 2000, the PSC granted Montana Power an interim electric rate increase of approximately $14,500,000, with hearings on this submission beginning in January 2001. On May 8, 2001, Montana Power received a final order from the PSC resulting in an annual delivery service revenue adjustment of $16,000,000, including the $14,500,000 interim increase granted on November 28, 2000.

On June 27, 2001, the PSC issued an order stating that they continue to have jurisdiction over the utility business as a fully integrated public utility, in spite of the December 17, 1999 sale of our electric generating facilities. The order requires that, if we desire a power supply rate change at the end of the rate moratorium on July 1, 2002, we must make a filing containing information that supports what rates would be if the regulatory system in place prior to deregulation remained intact. Montana Power filed a motion for reconsideration with the PSC, which was subsequently denied. Montana Power has since filed a complaint against the PSC in Montana State District Court in Helena, disputing this order. We cannot predict the ultimate outcome of this matter or its potential effect on our financial position or results of operation.

Natural Gas Rates

As discussed above, in August 2000, Montana Power filed a combined request for increased natural gas and electric rates with the PSC. Montana Power requested increased annual natural gas revenues of approximately $12,000,000, with a proposed interim annual increase of approximately $6,000,000. On November 28, 2000, the PSC granted Montana Power an interim natural gas rate increase of approximately $5,300,000. On May 8, 2001, Montana Power received a final order from the PSC resulting in an annual delivery and gas storage service revenue increase of $4,300,000. Because the amount established in the final order was less than the interim order, Montana Power began including a credit for the difference collected from November 2000 through May 2001, with interest, in customers' bills over a six-month period starting October 1, 2001.

In January 2001, Montana Power submitted to the PSC an Annual Gas Cost Tracker requesting an increase of approximately $51,000,000. At that time, Montana Power also submitted a Compliance Filing for a credit of approximately $32,500,000 associated with a sharing of the proceeds from the sale of gathering and production properties previously included in the natural gas utility's rate base. As a result, effective February 1, 2001, Montana Power began collecting a net amount of approximately $18,500,000 in revenues over a one-year period. In September 2001, after all testimony addressing the amount of sharing had been filed with the PSC, Montana Power reached an agreement with intervening parties to increase the amount of the credit to approximately $56,300,000. This $23,800,000 increase, along with approximately $5,300,000 in interest from the date of sale, was charged to expense during 2001 and will be credited to customers' bills over a two-year period beginning January 1, 2002.

On December 7, 2001, Montana Power filed our Annual Gas Cost Tracker request with the PSC for the tracking year beginning November 1, 2001.

FERC

Through a filing with FERC in April 2000, we are seeking recovery of transition costs associated with serving two wholesale electric cooperatives. A FERC decision on this filing, which corresponds with our transition-costs recovery proceedings with the PSC in Montana, has been on hold pending a PSC Tier II order. On January 31, 2002, the Montana PSC approved a stipulation settling transition cost recovery for retail customers in Montana. Discussions with the wholesale electric cooperatives involved in the FERC filing are expected to resume in the near future.

❑ 1999 SALE OF ELECTRIC GENERATING ASSETS

Assets Sold

On December 17, 1999, in accordance with the Asset Purchase Agreement entered into with PPL Montana, Montana Power sold substantially all of our electric generating assets and related contracts. Montana Power also sold an immaterial amount of associated transmission assets, totaling less than 40 miles. The asset sale did not include the Milltown Dam near Missoula, Montana (gross capacity of approximately 3 MWs) or any of our QF purchase-power contracts. It also did not include our leased share of the Colstrip Unit 4 generation or transmission assets.

As expected, the sale of our electric generating assets in December 1999 reduced the utility's net income for 2000. Utility revenues decreased because of discontinued off-system revenues that related to the electric generating assets sold. In addition, we no longer earn a return on our shareholders' investment in the electric generating assets. Before the sale, revenues covered the costs of operating the generating plants, taxes and interest, and earned a return on our shareholders' investment. Since the sale, we continue to bill our core customers for energy supply, but now these revenues recover the costs of the power that we purchase to serve these customers. The energy that we formerly generated and sold to core customers is now purchased pursuant to buyback contracts. The maximum price that we pay for power in the buyback contracts, $22.25/MWh, represents our net fully allocated supply costs of service in current rates, replacing operations and maintenance expense, property tax expense, depreciation expense, and return on investment associated with the electric generating assets.

In the sale of these assets, Montana Power generally retained all pre-closing obligations, and the purchaser generally assumed all post-closing obligations. However, with respect to environmental liabilities, the purchaser assumed all pre-closing (with certain limited exceptions) and post-closing environmental liabilities associated with the purchased assets.

While the purchaser assumed pre-closing environmental liabilities, Montana Power agreed to indemnify the purchaser from these pre-closing environmental liabilities, including a limited indemnity obligation for losses arising from required remediation of pre-closing environmental conditions, whether known or unknown at the closing, limited to:

- 50 percent of the loss. (Our share of this indemnity obligation at the Colstrip Project is limited to our pro-rata share of this 50 percent based on our pre-sale ownership share.)
- A two-year period after closing for unknown conditions. The indemnity for required remediation of pre-closing conditions known at the time of the closing continues indefinitely.
- An aggregate amount no greater than 10 percent of the purchase price paid for the assets.

Montana Power has received claim notices related to this indemnity obligation. Based on available information, we do not expect this indemnity claim on the indemnity obligation to have a material adverse effect on our combined financial position, results of operations, or cash flows.

Cash Proceeds

At December 31, 1999, we recorded a regulatory liability and related deferred income tax to reflect the generation sale proceeds in excess of book value. The Montana Power's liability, which was determined in the Tier II docket, is approximately $250,000,000 before income taxes. This liability represents a deferral of the gain on the generation sale and nothing has been reflected in the Statement of Income.

As part of our Tier II filing, we deducted from the regulatory liabilities approximately $15,000,000 of other after-tax generation-related transition costs and approximately $65,600,000 of regulatory asset transition costs. The other generation-related transition costs consist mainly of environmental costs and costs to retire debt. The regulatory asset transition costs consist mainly of capitalized conservation costs and carrying charges associated with Colstrip Unit 3.

Montana Power used a portion of the net cash proceeds received (excluding the proceeds in excess of book value) to purchase treasury shares of its common stock, to reduce debt, and to fund projects involving expansion of Touch America, a wholly owned subsidiary of Montana Power.

NOTE 3 - INCOME TAX EXPENSE

Income before income taxes for the years ended December 31, 2001 and 2000 was as follows:

	2001	2000
	(Thousands of Dollars)	
United States	$ (47,273)	$ (4,173)
Canada	37	237
	$ (47,236)	$ (3,936)

Income tax benefit as shown in the Statement of Income consists of the following components:

	2001	2000
	(Thousands of Dollars)	
Current		
United States	$ (16,101)	$ 6,706
Canada	38	16
State	4,077	(861)
	(11,986)	5,861
Deferred		
United States	7,298	(20,448)
State	373	(1,747)
	7,671	(22,195)
	$ (4,315)	$ (16,334)

The provision (benefit) for income taxes differs from the amount of income tax determined by applying the applicable U. S. statutory federal rate to pretax income as a result of the following differences:

	2001	2000
	(Thousands of Dollars)	
Computed "expected" income tax benefit	$ (16,533)	$ (1,378)
Adjustments for tax effects of:		
Tax credits	(445)	(167)
State income tax, net.	4,560	(4,734)
Reversal of utility book/tax Depreciation	4,473	4,119
Other	3,630	(14,174)
Actual income tax benefit	$ (4,315)	$ (16,334)

Under Montana regulations, certain tax benefits flow through to customers on a basis consistent with the accelerated deduction of expenses for income tax purposes. As such, when these expenses are recognized for financial reporting purposes, there is not an offsetting tax savings. During periods of income, our utility's effective tax rate is higher than the statutory rate due to this timing difference. During periods of losses, tax benefits will appear lower than expected.

Deferred tax liabilities (assets) are comprised of the following at December 31:

	2001	2000
	(Thousands of Dollars)	
Plant related	$ 198,104	$ 221,632
Other	37,070	36,063
Gross deferred tax liabilities	235,174	257,695
Amortization of gain on sale/leaseback	(3,801)	(4,681)
Investment tax credit amortization	(8,265)	(14,056)
Other	(163,866)	(154,322)
Gross deferred tax assets	(175,932)	(173,059)
Net deferred tax liabilities	$ 59,242	$ 84,636

The change in net deferred tax liabilities differs from current year deferred tax expense as a result of the following:

	Thousands of Dollars
Change in deferred tax............................	$ (25,394)
Regulatory assets related to income taxes...........	27,678
Benefit restoration plan equity adjustment..........	1,022
Pension plan equity adjustment.....................	5,904
Amortization of investment tax credits.............	(445)
Transfer of MSC balance to MPC.....................	(1,094)
Deferred tax expense............................	$ 7,671

NOTE 4 - PREFERRED STOCK

At December 31, 2001, Montana Power had 5,000,000 authorized shares of preferred stock. Montana Power's preferred stock is in three series as detailed in the following table:

Series	Stated and Liquidation Price*	Shares Issued and Outstanding 2001	Shares Issued and Outstanding 2000	Thousands of Dollars 2001	Thousands of Dollars 2000
$6.875	$100	360,800	360,800	$36,080	$36,080
6.00	100	159,589	159,589	15,959	15,959
4.20	100	60,000	60,000	6,025	6,025
Discount		-	-	(410)	(410)
		580,389	580,389	$57,654	$57,654

*Plus accumulated dividends.

At a special meeting of Montana Power shareholders held on September 21, 2001, shareholders representing more than two-thirds of Montana Power's outstanding common stock approved (among others) the following proposals:

- Holders of Preferred Stock, $6.875 Series, of Montana Power will receive one share of Touch America Holdings, Inc. Preferred Stock, $6.875 Series, for each share of Montana Power Preferred Stock.
- The redemption of Montana Power's outstanding Preferred Stock, $4.20 Series, and Preferred Stock, $6.00 Series.

Responsibility for the preferred stock has reverted to Touch America with the February 15, 2002 sale of the utility to NorthWestern.

NOTE 5 - COMMON STOCK

❑ **SHARE REPURCHASE PROGRAM**

In 1998, the Board of Directors authorized a share repurchase program over the next five years to repurchase up to 20,000,000 shares, (approximately 18 percent of our then-outstanding common stock) on the open market or in privately negotiated transactions. As of December 31, 2001, we had 103,774,500 common shares outstanding. The number of shares to be purchased and the timing of the purchases will be based on the level of cash balances, general business conditions, and other factors, including alternative investment opportunities. As of December 31, 2001, we had acquired 6,616,000 shares of common stock at an average cost per share of approximately $31.085. We have shown the total cost of $205,656,000 as "Reacquired Capital Stock" on the Comparative Balance Sheet.

❑ **SHAREHOLDER PROTECTION RIGHTS PLAN**

We have a Shareholder Protection Rights Plan (SPRP) that provides one preferred share purchase right on each outstanding common share. Each purchase right entitles the registered holder, upon the occurrence of certain events, to purchase from us one one-hundredth of a share of Participating Preferred Shares, A Series, without par value. If it should become exercisable, each purchase right would have economic terms similar to one share of common stock. The purchase rights trade with the underlying shares and will, except under certain circumstances described in the SPRP, expire on June 6, 2009, unless redeemed earlier or exchanged by us.

❑ DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN

Our Dividend Reinvestment and Stock Purchase Plan permits participants to: (a) acquire additional shares of common stock through the reinvestment of dividends on all or any specified number of common and/or preferred shares registered in their own names, or through optional cash payments of up to $60,000 per year; and (b) deposit common and preferred stock certificates into their Plan accounts for safekeeping. It also allows for other interested investors (residents of certain states) to make initial purchases of its common shares with a minimum of $100 and a maximum of $60,000 per year.

In conjunction with the divestiture of our energy businesses and our transition to a telecommunications enterprise, our Board of Directors voted in October 2000 to eliminate the dividend payment on our common stock effective the first quarter 2001. The final quarterly dividend on our common stock was $0.20 per share, payable on November 1, 2000. The Board's decision did not affect dividends on our preferred stock.

❑ RETIREMENT SAVINGS PLAN

We have a 401(k) Retirement Savings Plan that covers eligible employees. We contribute, on behalf of the employee, a matching percentage of the amount contributed to the Plan by the employee. In 1990, we borrowed $40,000,000 at an interest rate of 9.2 percent to be repaid in equal annual installments over 15 years. The proceeds of the loan were lent on similar terms to the Plan Trustee, which used the proceeds to purchase 3,844,594 shares of our common stock. Shares acquired with loan proceeds are allocated monthly to Plan participants to help meet the Company's matching obligation. The loan, which is reflected as long-term debt, is offset by a similar amount in common shareholders' equity as unallocated stock. Our contributions plus the dividends on the shares held under the Plan are used to meet principal and interest payments on the loan with the Plan Trustee. As principal payments on the loan are made, long-term debt and the offset in common shareholders' equity are both reduced. At December 31, 2001, 3,012,646 shares had been allocated to the participants' accounts. We recognize expense for the Plan using the Shares Allocated Method, and the pretax expense was $3,385,000 and $2,570,000 for 2001 and 2000, respectively.

On February 15, 2002, Montana Power retired the ESOP notes. For more information regarding the ESOP notes, see Note 7, "Long-Term Debt."

The ESOP Plan was transferred to Touch America prior to the sale of the utility business to NorthWestern. The utility no longer maintains an employee stock ownership plan.

❑ LONG-TERM INCENTIVE PLAN

Under the Long-Term Incentive Plan, we have issued options to our employees. Options issued to employees are not reflected in balance sheet accounts until exercised, at which time: (1) authorized, but un-issued shares are issued to the employee; (2) the capital stock account is credited with the proceeds; and (3) no charges or credits to income are made.

Options were granted at the average of the high and low prices as reported on the New York Stock Exchange composite tape on the date granted and expire ten years from that date.

Option activity is summarized below:

	2001		2000	
	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price
Outstanding, beginning of year	4,076,244	$28.43	3,280,325	$25.63
Granted	35,500	17.38	1,199,545	34.36
Exercised ..	32,984	13.49	149,834	17.07
Cancelled ..	1,051,313	27.75	253,792	26.88
Outstanding, end of year	3,027,447	$28.70	4,076,244	$28.43

Shares under option at December 31, 2001, are summarized below:

	Options Outstanding			Options Exercisable	
Exercise Price Range	Shares	Wtd Avg Exercise Price	Wtd Avg Exercise Life	Shares	Wtd Avg Exercise Price
$6.45	6,000	$ 6.45	10 yrs	-	$ -
$10.73 to $14.29	154,725	11.11	4 yrs	148,725	11.08
$18.00 to $24.66	399,929	19.60	7 yrs	317,446	18.62
$26.53 to $32.50	1,689,863	28.72	8 yrs	1,194,039	27.67
$35.36 to $38.69	776,930	37.00	8 yrs	394,930	35.36
	3,027,447			2,055,140	

As permitted by SFAS No. 123, "Accounting for Stock-Based Compensation," we have elected to follow Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25), and related interpretations in accounting for our employee stock options. Under APB 25, because the exercise price of the employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recognized. Disclosure of pro-forma information regarding net income is required by SFAS No. 123. This information has been determined as if we had accounted for our employee stock options under the fair value method of that statement. The weighted-average fair value of options granted in 2001 and 2000 was $10.23 and $16.35 per share, respectively. We employed the binomial option-pricing model to estimate the fair value of each option grant on the date of grant. We used the following weighted-average assumptions for grants in 2001 and 2000, respectively: (1) risk-free interest rate of 5.07 percent and 6.05 percent; (2) expected life of 7.0 years and 6.2 years; (3) expected volatility of 51.00 percent and 42.00 percent; and (4) a dividend yield of zero percent for both years. Had we elected to use SFAS No. 123, compensation expense would have increased $10,904,000 in 2001 and $11,827,000 in 2000. The 2001 and 2000 pro forma net income after preferred dividends would be $5,015,000 and $188,632,000, respectively.

NOTE 6 - COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUST

We established Montana Power Capital I (Trust) as a wholly owned business trust to issue common and preferred securities and hold Junior Subordinated Deferrable Interest Debentures (Subordinated Debentures) that we issue. At December 31, 2001 and 2000, the Trust had issued 2,600,000 units of 8.45 percent Cumulative Quarterly Income Preferred Securities, Series A (QUIPS). Holders of the QUIPS are entitled to receive quarterly distributions at an annual rate of 8.45 percent of the liquidation preference value of $25 per security. The sole asset of the Trust is $67,000,000 of our Subordinated Debentures, 8.45 percent Series due 2036. The Trust will use interest payments received on the Subordinated Debentures that it holds to make the quarterly cash distributions on the QUIPS. The QUIPS' $65,000,000 liquidation value is included with "Other Long Term Debt" on the Comparative Balance Sheet.

Since November 6, 2001, we can wholly redeem the Subordinated Debentures at any time, or partially redeem the Subordinated Debentures from time to time. Upon repayment of the Subordinated Debentures at maturity or early redemption, the Trust Securities must be redeemed. In addition, we can terminate the Trust at any time and cause the pro rata distribution of the Subordinated Debentures to the holders of the Trust Securities.

Besides our obligations under the Subordinated Debentures, we have agreed to certain Back-up Undertakings. We have guaranteed, on a subordinated basis, payment of distributions on the Trust Securities, to the extent the Trust has funds available to pay such distributions. We also have agreed to pay all of the expenses of the Trust. Considered together with the Subordinated Debentures, the Back-up Undertakings constitute a full and unconditional guarantee of the Trust's obligations under the QUIPS. We are the owner of all the common securities of the Trust, which constitute 3 percent of the aggregate liquidation amount of all the Trust Securities.

NOTE 7 - LONG-TERM DEBT

The Mortgage and Deed of Trust (Mortgage) imposes a first mortgage lien on all physical properties owned, exclusive of subsidiary company assets and certain property and assets specifically excepted. The obligations collateralized are First Mortgage Bonds, including those First Mortgage Bonds designated as Secured Medium-Term Notes (MTNs) and those securing Pollution Control Revenue Bonds.

Long-term debt consists of the following:

	December 31, 2001	December 31, 2000
	(Thousands of Dollars)	
First Mortgage Bonds:		
7% series, due 2005	$ 5,386	$ 5,386
7.30% series, due 2006	150,000	-
8 1/4% series, due 2007	365	365
8.95% series, due 2022	1,446	1,446
Secured Medium-Term Notes- maturing 2003-2008 7.20%-8.11%	28,000	28,000
Pollution Control Revenue Bonds:		
City of Forsyth, Montana		
6 1/8% series, due 2023	90,205	90,205
5.90% series, due 2023	80,000	80,000
Unsecured Medium-Term Notes Series B- maturing 2001-2026 7.20%-8.11%	40,000	100,000
ESOP Notes Payable - 9.20%, due 2004	12,666	16,197
8.45% QUIPS	65,000	65,000
Unamortized Discount and Premium	(3,211)	(2,444)
	$469,857	$384,155

On November 27, 2001, we issued $150,000,000 of our 7.3 percent series First Mortgage Bonds (Bonds) due December 1, 2006. The net proceeds from the sale of the bonds were used to repay outstanding short-term debt and for general corporate purposes. In addition, we retired the 9.20 percent ESOP notes on February 15, 2002 with a portion of the proceeds.

On April 6, 2001, we retired $60,000,000 of our variable rate Series B Unsecured Medium Term Notes at maturity.

Scheduled debt repayments on the long-term debt outstanding at December 31, 2001, amount to: $12,666,000 in 2002; $15,000,000 in 2003; $5,386,000 in 2005; $165,000,000 in 2006; and $271,805,000 thereafter.

NOTE 8 - SHORT-TERM BORROWING

Our committed and uncommitted credit lines expired at the end of November 2001 and were not renewed by December 31, 2001. On November 21, 2001, Montana Power issued $150,000,000 in First Mortgage Bonds and used the proceeds from the bonds to repay the $60,000,000 balance outstanding under committed credit line, repay short-term borrowings, and repay an intercompany loan between Montana Power and Entech. The remaining balance was used for existing cash requirements and to redeem our ESOP notes. At December 31, 2001, we had no outstanding short-term borrowing.

At December 31, 2000, we had outstanding notes payable to banks for $75,000,000 at a weighted average annual interest rate of 8.05 percent. Of those outstanding notes, $25,000,000 were issued from our committed lines of credit and the other $50,000,000 from our uncommitted lines of credit.

NOTE 9 - RETIREMENT PLANS

Montana Power maintains trusteed, noncontributory retirement plans covering substantially all of our employees. Prior to 1998, our retirement benefits were based on salary, years of service, and social security integration levels. In 1998, we amended our retirement plan's benefit provisions. Our retirement benefits are now based on salary, age, and years of service. Northwestern has agreed to assume certain retirement plans and participants and maintain such plans or equivalent plans for a period of two years.

Our plan assets consist primarily of domestic and foreign corporate stocks, domestic corporate bonds, and United States Government securities.

We also have an unfunded, nonqualified benefit plan for senior management executives and directors. In December 1998, we froze the benefits earned and curtailed the plan. We own life insurance policies, the cash value/death benefit of which is intended to finance this plan.

As a result of the sale of our electric generating assets to PPL Montana, 454 participants related to electric generation operations were curtailed from the retirement plan and approximately $22,700,000 in assets were transferred from the retirement plan trust in December 1999. Pursuant to the agreement, when the calculation was finalized in February 2000, approximately $3,200,000 of additional assets were transferred to the PPL trust. In accordance with SFAS 88, we calculated a curtailment gain of approximately $4,100,000 and a settlement gain of approximately $7,800,000 in 1999. Due to regulatory accounting treatment, the gains were recorded as regulatory liabilities or offsets to regulatory assets, resulting in no income statement impact.

We offered a Special Retirement Program (SRP) to certain eligible employees during 2000. The SFAS 88 special termination charge resulting from 201 utility participants electing the SRP amounted to approximately $9,814,000. Due to regulatory accounting treatment, the expense was recorded as regulatory liabilities or offsets to regulatory assets, resulting in no income statement impact.

We also provide certain health care and life insurance benefits for eligible retired employees. In 1994, we established a pre-funding plan for postretirement benefits for utility employees retiring after January 1,1993. The plan assets consist primarily of domestic and foreign corporate stocks, domestic corporate bonds, and United States Government securities. The PSC allows us to include in rates all utility Other Postretirement Benefits costs on the accrual basis provided by SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions."

We also have a voluntary retirement savings plan in conjunction with our retirement plans. Through October 30, 2001, Montana Power contributed a matching percentage comprised of shares of Montana Power stock from a leveraged Employee Stock Ownership Plan (ESOP) arrangement and Montana Power shares purchased on the open market. Beginning November 1, 2002, we make cash contributions matching employee contributions up to 4 percent of their salaries. For costs associated with these plans and for information about the transfer of the ESOP Plan to Touch America, see Note 5, "Common Stock."

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of plan assets over the two-year period ending December 31, 2001, and a statement of the funded status as of December 31 of both years:

	Pension Benefits		Other Benefits	
	2001	2000	2001	2000
	(Thousands of Dollars)			
Change in benefit obligation:				
Benefit obligation at January 1.	$ 235,515	$ 197,333	$ 23,168	$ 18,918
Service cost on benefits earned.	3,676	4,090	420	430
Interest cost on projected benefit obligation...........	16,992	15,893	1,851	1,561
Plan amendments................	1,717	7,578	-	-
Assumption changes.............	-	5,859	-	-
Actuarial (gain)/loss..........	24,909	(4,988)	3,598	4,920
Adjustments for liability transfers....................	14,072	11,630	(324)	-
Special termination benefits....	-	9,814	-	-
Gross benefits paid............	(16,488)	(11,694)	(4,688)	(2,661)
Benefit obligation at December 31..................	$ 280,393	$ 235,515	$ 24,025	$ 23,168
Change in plan assets:				
Fair value of plan assets at January 1....................	$ 223,921	$ 230,606	$ 9,706	$ 9,916
Actual return/(loss) on plan assets.......................	(4,917)	(4,955)	107	329
Employer contributions..........	1,834	1,818	746	2,122
Acquisitions/divestitures.......	-	(3,200)	-	-
Assets allocated (to)/from related companies............	10,793	11,346	-	-
Gross benefits paid............	(16,488)	(11,694)	(4,688)	(2,661)
Fair value of plan assets at December 31..................	$ 215,143	$ 223,921	$ 5,871	$ 9,706
Reconciliation of funded status:				
Funded status at end of year....	$ (65,250)	$ (11,594)	$ (18,153)	$ (13,461)
Unrecognized net:				
Actuarial gain...............	24,642	(22,707)	2,855	(97)
Prior service cost...........	20,459	21,295	1,248	1,459
Transition obligation.........	(129)	(196)	8,721	10,034
Acquisitions/divestitures.....	3,615	-	-	-
Net amount recognized at December 31................	$ (16,663)	$ (13,202)	$ (5,329)	$ (2,065)

The following table provides the amounts recognized in the statement of financial position as of December 31:

	Pension Benefits		Other Benefits	
	2001	2000	2001	2000
	(Thousands of Dollars)			
Prepaid benefit cost	$ 2,170	$ 11,028	$ -	$ -
Accrued benefit cost	(18,833)	(24,230)	(5,329)	(2,065)
Additional minimum liability	(40,374)	(2,594)	-	-
Intangible asset	21,367		-	-
Regulatory asset - pension plan	14,990	-	-	-
Accum. other comprehensive inc.	4,017	2,594	-	-
Net amount recognized at December 31	$ (16,663)	$ (13,202)	$ (5,329)	$ (2,065)

The following tables provide the components of net periodic benefit cost for the pension and other postretirement benefit plans, portions of which have been deferred or capitalized, for fiscal years 2001, 2000, and 1999:

	Pension Benefits	
	2001	2000
	(Thousands of Dollars)	
Service cost on benefits earned	$ 3,676	$ 4,090
Interest cost on projected benefit obligation	16,992	15,893
Expected return on plan assets	(17,921)	(20,273)
Amortization of:		
Transition obligation	(47)	(49)
Prior service cost	1,947	1,607
Actuarial gain	67	(2,830)
Net periodic benefit cost (credit)	4,714	(1,562)
Special termination benefit charge	-	9,814
Curtailment (gain)/loss	-	-
Settlement gain	-	-
Net periodic benefit cost (credit) after curtailments and settlements	$ 4,714	$ 8,252

	Other Benefits 2001	Other Benefits 2000
	(Thousands of Dollars)	
Service cost on benefits earned	$ 420	$ 430
Interest cost on projected benefit obligation	1,851	1,561
Expected return on plan assets	(706)	(819)
Amortization of:		
Transition obligation	792	837
Prior service cost	138	146
Actuarial gain	-	(128)
Net periodic benefit cost (credit)	2,495	2,027
Curtailment (gain)/loss	-	-
Net periodic benefit cost (credit) after curtailments and settlements	$ 2,495	$ 2,027

In 2001, funding for pension costs was less than SFAS No. 87, "Employers Accounting for Pensions," pension expense by $3,138,000. In 2000, pension costs exceeded SFAS No. 87 pension expense by $3,078,000. The PSC allows recovery for the funding of pension costs through rates. Any differences between funding and expense are deferred for recognition in future periods. At December 31, 2001, the regulatory liability was $7,487,000.

The following assumptions were used in the determination of actuarial present values of the projected benefit obligations:

	Pension Benefits 2001	Pension Benefits 2000	Other Benefits 2001	Other Benefits 2000
Weighted average assumptions as of December 31:				
Discount rate	7.00%	7.50%	7.00%	7.50%
Expected return on plan assets	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	4.40%	4.40%	4.40%	4.40%

Assumed health care costs trend rates have a significant effect on the amounts reported for the health care plans. A change of 1 percent in assumed health care cost trend rates would have the following effects:

(Thousands of Dollars)	1% Increase	1% Decrease
Effect on the total of service and interest cost components of net periodic post-retirement health care benefit cost	$ 95	$ (82)
Effect on the health care component of the accumulated postretirement benefit obligation	687	(604)

The assumed 2001 health care cost trend rates used to measure the expected cost of benefits covered by the plans is 9.00 percent. The trend rate decreases through 2007 to 5.50 percent.

NOTE 10 - CONTINGENCIES

❑ **KERR PROJECT**

A FERC order that preceded the sale of the Kerr Project required Montana Power to implement a plan to mitigate the effect of the Kerr Project operations on fish, wildlife, and habitat. To implement this plan, Montana Power was required to make payments of approximately $135,000,000 between 1985 and 2020, the term during which we would have been the licensee. The net present value of the total payments, assuming a 9.5 percent annual discount rate, was approximately $57,000,000, an amount we recognized as license costs in plant and long-term debt on the Comparative Balance Sheet in 1997. In the sale of the Kerr Project, the purchaser of the electric generating assets assumed the obligation to make post-closing license compliance payments.

In December 1998 and January 1999, Montana Power requested a review by the United States Court of Appeals for the District of Columbia Circuit of this order and another FERC order which included the United States Department of Interior's conditions. In December 2000, FERC issued an order approving a settlement among the parties. On February 15, 2001, the Circuit Court dismissed the petitions for review. Consequently, the approximately $24,000,000 that Montana Power paid into escrow in 2000 was released to the Confederated Salish and Kootenai Tribes (Tribes) to be used in accordance with the terms of the settlement. We have also transferred 669 acres of land on the Flathead Indian Reservation to the Tribes. With the payment and the transfer of land, we have fulfilled our obligations under the terms of this settlement. Because PPL Montana, the purchaser, assumed the obligation in excess of $24,000,000, the basis in the properties sold decreased and the regulatory liability associated with the deferred gain on the sale increased accordingly.

❑ **LONG-TERM POWER SUPPLY AGREEMENTS**

Long-term power supply agreements, primarily an agreement with a large industrial customer, exposed us to losses and potential future losses mainly because of unusually high electric energy market prices. To eliminate our exposure to expected future losses through December 2002 when the agreement with that customer terminated, we executed a termination agreement effective June 30, 2001. Under the termination agreement, we made a one-time payment of $62,500,000 to the customer and ended our obligations under this power supply agreement. We recorded a pretax loss of $62,500,000, or approximately $37,900,000 after income taxes, in the second quarter 2001. Prior to the termination agreement, we recorded pretax losses associated with the power supply agreement of approximately $2,500,000 in the first quarter 2001, and $22,500,000 in the second quarter 2001, and approximately $16,200,000 for the year ended December 31, 2000.

- **CLASS ACTION LAWSUIT**

On August 16, 2001, eight individuals filed a lawsuit in Montana State District Court, naming Montana Power, eleven of its current Board of Directors, three officers of both Touch America and Montana Power, and PPL Montana as defendants. In their complaint, the plaintiffs allege that Montana Power and its directors and officers had a legal obligation and a fiduciary duty to obtain shareholder approval before the sale of our former electric generation assets to PPL Montana. On September 14, 2001, the complaint was amended to add one other current officer of Touch America, one other current officer of Montana Power, and our investment banking consultants as additional defendants. As previously reported, Montana Power completed the sale of the electric generation assets to PPL Montana in December 1999. The plaintiffs further allege that because Montana Power shareholders did not vote, the sale of the generation assets is void and PPL Montana is holding these assets in constructive trust for the shareholders.

Alternatively, the plaintiffs allege that Montana Power shareholders should have been allowed to vote on the sale of the generation assets and, if an appropriate majority vote was obtained in favor of the sale, the shareholders should have been given dissenters' rights. The plaintiffs also make various claims of breaches of duty and negligence against the Board of Directors and the individual officers. The plaintiffs have indicated that they will seek court approval to proceed with this suit as a class action.

It is Montana Power's position that Montana Power and its former directors and officers, and one current officer, have fully complied with their statutory and fiduciary duties. Accordingly, Montana Power is defending the suit vigorously. Montana Power filed a motion to dismiss the complaint in late November 2001. At this early stage, however, we cannot predict the ultimate outcome of this matter or how it may affect our combined financial position, results of operations, or cash flows.

- **MISCELLANEOUS**

We are parties to various other legal claims, actions, and complaints arising in the ordinary course of business. We do not expect the conclusion of any of these matters to have a material adverse effect on our combined financial position, results of operations, or cash flows.

NOTE 11 - COMMITMENTS

- **PURCHASE COMMITMENTS**

Electric Utility

The Public Utilities Regulatory Policies Act (PURPA) requires a public utility to purchase power from QFs at a rate equal to what it would pay to generate or purchase power. These QFs are power production or co-generation facilities that meet size, fuel use, ownership, and operating and efficiency criteria specified by PURPA. The electric utility has 15 long-term QF contracts with expiration terms ranging from 2003 through 2032 that require us to make payments for energy capacity and energy received at prices established by the PSC. Three contracts account for 96 percent of the 101 MWs of capacity provided by these facilities. Montana's 1997 Electric Act designates above-market portion of the QF costs as Competitive Transition

Costs (CTCs) and allows for their recovery. For more information about CTCs, see Note 2, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets".

Montana's 1997 Electric Act also designated Montana Power as the default power supplier for those customers who had not chosen another supplier by July 1, 2002. To fulfill that obligation, there was included in the Asset Purchase Agreement with PPL Montana, dated as of October 31, 1998 and amended June 29, 1999 and October 29, 1999, two Wholesale Transition Service Agreements (WTSAs), effective December 17, 1999. One agreement terminated at December 31, 2001. The other agreement continues to commit us to purchase through June 2002 any power requirements remaining after having received power from the QFs and Milltown Dam, and prices the power purchased from PPL Montana at a market index, with a monthly floor and an annual cap.

In its 2001 session, the Montana Legislature passed House Bill 474, which extends the transition period of electric deregulation in Montana from July 1, 2002 to June 30 2007 and, therefore, our obligation as a default supplier through June 30, 2007. We entered into three power purchase agreements in October 2001 that enable us to satisfy, in part, our "Default Supply" obligation. These agreements commit us to purchase a total of 561 MWs per hour during peak hours and 411 MWs per hour during the off-peak hours in the first year of the extended transition period. In the remaining years of the transition period, these agreements also obligate us to purchase 450 MWs per hour during the peak hours and 300 MWs per hour during the off-peak hours. These purchases are included in the "Default Supply Portfolio" filing with the PSC (Docket No.D2001.10.144) dated October 29, 2001. House Bill 474 also provides for the complete recovery in rates of the default supplier's costs that are prudently incurred to supply electric energy. For more information about electric deregulation, see Note 2, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets," in the "Electric Deregulation" section.

Natural Gas Utility

Since 1998, because of uncertainty about the number and timing of customers who could choose another natural gas supplier under the provisions of Montana's 1997 Natural Gas Act, Montana Power entered primarily into one-year take-or-pay contracts with Montana natural gas producers. We currently have six of these contracts, five of which expire in 2002, and one in 2006. After July 1, 2002, we are not obligated to supply natural gas to those who do not choose another supplier. We have a request before the PSC to designate us as the natural gas default supplier for the five-year period beyond July 1, 2002. Upon such designation, we will secure additional supply contracts to meet the needs of our customers.

Contractual Payments and Present Value

Total payments under all of these contracts for the prior three years were as follows:

	Electric	Natural Gas	Total
	(Thousands of Dollars)		
2001	$263,924	$ 16,764	$280,688
2000	272,075	7,101	279,176
1999	61,274	4,069	65,343

Under the above agreements, the present value of future minimum payments, at a discount rate of 3.615 percent, is as follows:

	Electric	Natural Gas	Total
	(Thousands of Dollars)		
2002	$103,724	$ 8,871	$112,595
2003	118,985	613	119,598
2004	104,289	612	104,901
2005	100,677	593	101,270
2006	87,723	566	88,289
Remainder	241,009	-	241,009
	$756,407	$11,255	$767,662

❑ **LEASE COMMITMENTS**

On September 24, 1997, Montana Power entered into a seven-year operating lease with a banking institution - for an automated meter reading system - with annual payments of approximately $2,400,000. This lease was terminated by NorthWestern on February 15, 2002. We have no other material minimum operating lease payments and capitalized leases are not material.

Rental expense for the prior two years was $9,700,000 for 2001, $6,800,000 for 2000, and $56,316,000 for 1999.

NOTE 12 - NEW ACCOUNTING PRONOUNCEMENTS

❑ **SFAS NOS. 141, 142, 143, AND 144**

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, "Business Combinations." SFAS No. 141 eliminates the use of the pooling of interests method of accounting, and requires that all mergers and acquisitions be accounted for using the purchase method of accounting. SFAS No. 141 also establishes specific criteria for the recognition of intangible assets separately from goodwill and adds new disclosure requirements. This statement is effective for all mergers and acquisitions initiated after June 30, 2001. Adoption of this pronouncement is not expected to have a material impact on our financial position, results of operations, or cash flows.

In June 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangibles." The amortization provisions of SFAS No. 142 apply to goodwill and other intangibles acquired after June 30, 2001. For goodwill and other intangible assets acquired prior to July 1, 2001, adoption of SFAS No. 142 is required for fiscal years beginning after December 15, 2001. SFAS No. 142 primarily addresses the accounting for goodwill and intangible assets subsequent to their initial recognition. The provisions of SFAS 142:

- prohibit the amortization of goodwill and indefinite-lived intangible assets;
- require that reporting units be identified for the purpose of assessing potential future impairments of goodwill;
- remove the forty-year limitation on the amortization period of intangible assets that have finite lives; and

- prohibit amortization of the excess of cost over the underlying equity in the net assets of an equity-method investee that is recognized as goodwill.

In addition, SFAS No. 142 requires that goodwill be tested annually for impairment - and in interim periods if certain events occur indicating that the carrying value of goodwill and/or indefinite-lived intangible assets may be impaired - using a two-step process. The first step is to identify a potential impairment and, in transition, this step must be measured as of the beginning of the fiscal year. However, a company has six months from the date of adoption to complete the first step. The second step of the goodwill impairment test measures the amount of the impairment loss (measured as of the beginning of the year of adoption), if any, and must be completed by the end of the fiscal year. Intangible assets deemed to have an indefinite life will be tested for impairment using a one-step process which compares the fair value to the carrying amount of the asset as of the beginning of the fiscal year, and pursuant to the requirements of SFAS 142 will be completed during the first quarter of 2002. Any impairment loss resulting from the transitional impairment tests will be reflected as the cumulative effect of a change in accounting principle in the first quarter 2002. Adoption of this pronouncement is not expected to have a material impact on our financial position, results of operations, or cash flows.

In June 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a legal liability for an asset retirement obligation in the period it is incurred. The asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. This statement is effective for financial statements issued for fiscal years beginning after June 15, 2002. We are currently evaluating this pronouncement, but we do not expect it to have a material impact on our financial position, results of operations, or cash flows.

In August 2001, the FASB issued SFAS No. 144 "Accounting for the Impairment of Long-Lived Assets." SFAS No. 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2001. Adoption of this pronouncement is not expected to have a material impact on our financial position, results of operations, or cash flows.

Sch.19

MONTANA PLANT IN SERVICE - ELECTRIC (EXCLUDES UNIT 4)

	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Intangible Plant**					
3	301 Organization	$19,995		$19,995	$19,995	-
4	302 Franchises and Consents	2,004		2,004	2,004	-
5	303 Miscellaneous Intangible Plant	1,287,004		1,287,004	1,322,515	-2.69%
6	**Total Intangible Plant**	1,309,003	-	1,309,003	1,344,514	-2.64%
7						
8	**Production Plant**					
9						
10	**Steam Production**					
11	310 Land and Land Rights	-			1,292	-100.00%
12	311 Structures and Improvements	-			60,420	-100.00%
13	312 Boiler Plant Equipment	-			426,612	-100.00%
14	313 Engines, Engine Driven Generator	-			-	-
15	314 Turbogenerator Units	-			309,314	-100.00%
16	315 Accessory Electric Equipment	-			-	-
17	316 Misc. Power Plant Equipment	-			116,028	-100.00%
18	**Total Steam Production Plant**	-	-	-	913,666	-100.00%
19						
20	**Nuclear Production**					
21	320 - 325 Not Applicable					
22	**Total Nuclear Production Plant**	-	-	-	-	-
23						
24	**Hydraulic Production**					
25	330 Land and Land Rights	58,620		58,620	58,620	-
26	331 Structures and Improvements	119,451		119,451	119,451	-
27	332 Reservoirs, Dams and Waterways	8,993,976		8,993,976	8,976,477	0.19%
28	333 Water Wheel, Turbine, Generators	122,145		122,145	124,613	-1.98%
29	334 Accessory Electric Equipment	77,056		77,056	99,660	-22.68%
30	335 Misc. Power Plant Equipment	90,472		90,472	90,351	0.13%
31	336 Roads, Railroads and Bridges	26,282		26,282	60,077	-56.25%
32	**Total Hydraulic Production Plant**	9,488,002	-	9,488,002	9,529,249	-0.43%
33						
34	**Other Production**					
35	340 Land and Land Rights					
36	341 Structures and Improvements	30,746	30,746		10,083	-100.00%
37	342 Reservoirs, Dams and Waterways	112,084	112,084		-	-
38	343 Water Wheel, Turbine, Generators	-			-	-
39	344 Accessory Electric Equipment	2,255,293	2,255,293		14,772	-100.00%
40	345 Misc. Power Plant Equipment	249,277	249,277		17,411	-100.00%
41	346 Roads, Railroads and Bridges	7,554	7,554		-	-
42	**Total Other Production Plant**	2,654,954	2,654,954	-	42,266	-100.00%
43	**Total Production Plant**	12,142,956	2,654,954	9,488,002	10,485,181	-9.51%

Sch. 19	MONTANA PLANT IN SERVICE - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Plant**					
3	350 Land and Land Rights	15,720,230	-	15,720,230	15,616,467	0.66%
4	352 Structures and Improvements	4,281,552	-	4,281,552	3,996,250	7.14%
5	353 Station Equipment	125,393,870	-	125,393,870	125,260,188	0.11%
6	354 Towers and Fixtures	23,167,957	-	23,167,957	22,995,734	0.75%
7	355 Poles and Fixtures	117,952,468	710,150	117,242,318	116,313,874	0.80%
8	356 Overhead Conductors & Devices	105,681,375	594,293	105,087,082	104,757,788	0.31%
9	357 Underground Conduit	137,878	102,286	35,592	35,592	-
10	358 Undergrnd Conductors & Devices	1,410,535	554,036	856,499	856,499	-
11	359 Roads and Trails	2,372,509	44,906	2,327,603	2,279,222	2.12%
12	**Total Transmission Plant**	396,118,374	2,005,671	394,112,703	392,111,614	0.51%
13						
14	**Distribution Plant**					
15	360 Land and Land Rights	3,685,883	601	3,685,282	3,586,886	2.74%
16	361 Structures and Improvements	4,307,269	141,867	4,165,402	3,838,824	8.51%
17	362 Station Equipment	90,777,991	1,921,163	88,856,828	88,538,629	0.36%
18	363 Storage Battery Equipment	-		-	-	-
19	364 Poles, Towers, and Fixtures	111,242,277	223,224	111,019,053	105,459,072	5.27%
20	365 Overhead Conductors & Devices	68,369,346	326,659	68,042,687	65,756,192	3.48%
21	366 Underground Conduit	21,297,667	92,647	21,205,020	21,205,602	-
22	367 Undergrnd Conductors & Devices	74,135,704	2,519,355	71,616,349	62,552,790	14.49%
23	368 Line Transformers	125,204,524	715,091	124,489,433	121,556,740	2.41%
24	369 Services	62,076,751	214,774	61,861,977	59,404,266	4.14%
25	370 Meters	29,926,936	67,143	29,859,793	28,880,969	3.39%
26	371 Installations on Cust. Premises	-		-	-	-
27	372 Leased Property on Cust. Premises	-		-	-	-
28	373 Street Lighting and Signal Systems	38,271,785	19,872	38,251,913	37,091,174	3.13%
29	**Total Distribution Plant**	629,296,133	6,242,396	623,053,737	597,871,144	4.21%
30						
31	**General Plant**					
32	389 Land and Land Rights	414,128	-	414,128	415,080	-0.23%
33	390 Structures and Improvements	7,432,193	84,207	7,347,986	7,173,557	2.43%
34	391 Office Furniture and Equipment	987,968		987,968	838,042	17.89%
35	392 Transportation Equipment	24,831,400	93,890	24,737,510	24,436,827	1.23%
36	393 Stores Equipment	456,324	-	456,324	434,209	5.09%
37	394 Tools, Shop & Garage Equipment	4,242,472	35,749	4,206,723	4,184,788	0.52%
38	395 Laboratory Equipment	4,256,127	6,952	4,249,175	4,324,394	-1.74%
39	396 Power Operated Equipment	2,287,364		2,287,364	2,242,288	2.01%
40	397 Communication Equipment	19,588,240	74,172	19,514,068	19,830,270	-1.59%
41	398 Miscellaneous Equipment	204,084	73,861	130,223	132,373	-1.62%
42	399 Other Tangible Equipment	-	-	-	824,515	-100.00%
43	**Total General Plant**	64,700,300	368,831	64,331,469	64,836,343	-0.78%
44	**Total Plant in Service**	1,103,566,766	11,271,852	1,092,294,914	1,066,648,796	2.40%
45						
46	4101 El Plant Allocated from Common	51,528,766		51,528,766	23,746,825	116.99%
47	105 El Plant Held for Future Use	-		-	-	-
48	107 El Construction Work in Progress	8,135,564		8,135,564	1,236,057	558.19%
49	114.2 El Plant Acquisition Adjustment	3,106,285		3,106,285	3,106,285	-
50						
51	**TOTAL ELECTRIC PLANT**	$1,166,337,381	$11,271,852	$1,155,065,529	$1,094,737,963	5.51%

Sch. 20	MONTANA DEPRECIATION SUMMARY - ELECTRIC (EXCLUDES UNIT 4)						
	Functional Plant Class	Montana Plant Cost	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**						
2							
3	Steam Production	$913,666	($1,164,218)	$ -	($1,164,218)	($1,164,218)	-
4							
5	Nuclear Production						
6							
7	Hydraulic Production	9,529,249	5,836,127	-	5,836,127	5,317,515	5.48%
8							
9	Other Production	42,266	1,424,608	1,424,608	-	-	-
10							
11	Transmission	392,111,614	127,033,019	1,180,974	125,852,045	116,263,681	2.93%
12							
13	Distribution	597,871,213	238,492,480	2,540,017	235,952,463	215,781,511	3.84%
14							
15	General and Intangible	66,180,789	29,880,865	214,300	29,666,565	29,510,858	5.65%
16							
17	Common	23,746,825	15,637,175	-	15,637,175	4,975,285	5.38%
18							
19	**TOTAL DEPRECIATION**	$1,090,395,622	$417,140,056	$5,359,899	$411,780,157	$370,684,632	3.64%
20							
21							
22							
23							

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)- ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	151 Fuel Stock	$0		$0	$151,070	-100.00%
3						
4	154 Plant Materials & Operating Supplies					
5	Assigned and Allocated to:					
6	Operation & Maintenance	-		-	-	-
7	Construction	-		-	-	-
8	Production Plant	66,285		66,285	85,258	-22.25%
9	Transmission Plant	2,753,343		2,753,343	3,188,365	-13.64%
10	Distribution Plant	4,352,766		4,352,766	4,861,451	-10.46%
11						
12						
13	**TOTAL MATERIALS & SUPPLIES**	$7,172,394	$ -	$7,172,394	$8,286,144	-13.44%

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC			
		% Capital Structure	% Cost Rate	Weighted Cost
1	**Commission Accepted - Most Recent 1/**			
2				
3	Docket Number: 2000.8.113			
4	Order Number : 6271c			
5				
6	Common Equity	43.00%	10.75%	4.62%
7	Preferred Stock	6.97%	6.40%	0.45%
8	QUIPS Preferred 2/	7.86%	8.54%	0.67%
9	Long Term Debt	42.17%	6.46%	2.72%
10	**TOTAL**	100.00%		8.46%
11				
12	**Actual at Year End**			
13				
14	Common Equity	37.26%	10.75%	4.01%
15	Preferred Stock	7.03%	6.40%	0.45%
16	QUIPS Preferred 2/	7.92%	8.54%	0.68%
17	Long Term Debt 3/	47.79%	6.83%	3.26%
18	**TOTAL**	100.00%		8.40%
19				
20	1/ Docket 2000.8.113, Order 6271c specifies the authorized capital structure and associated costs for			
21	the regulated electric utility effective May 8, 2001.			
22				
23	2/ The cost of the QUIPS securities is treated as tax deductible for income tax purposes.			
24	See footnote on Schedule 25.			
25				
26	3/ The cost rate can not be tied directly to Schedule 24, which is presented on a consolidated basis.			

Sch. 23 STATEMENT OF CASH FLOWS (INCLUDES UNIT 4) - 1/

	Description	This year	Last Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$15,393,683	$199,490,689	-92.28%
4	Depreciation	55,281,111	48,266,339	14.53%
5	Amortization	94,914	94,939	-0.03%
6	Deferred Income Taxes - Net	(19,429,078)	(15,883,186)	-22.32%
7	Investment Tax Credit Adjustments - Net	(444,673)	(166,770)	-166.64%
8	Change in Operating Receivables - Net	231,253,843	(21,580,392)	1171.59%
9	Change in Materials, Supplies & Inventories - Net	599,764	(92,138)	750.94%
10	Change in Operating Payables & Accrued Liabilities - Net	(196,263,958)	(52,468,014)	-274.06%
11	Allowance for Funds Used During Construction (AFUDC)	(36,530)	(446,286)	91.81%
12	Change in Other Assets & Liabilities - Net	-	-	-
13	Other Operating Activities:			
14	Undistributed Earnings from Subsidiary Companies	(59,388,353)	(193,438,772)	69.30%
15	Amortization of Loss on Long-Term Sale of Power	-	-	-
16	Other (net)	(241,219,431)	4,975,607	-4948.04%
17	Change in Regulatory Assets	(3,089,595)	(15,464,321)	80.02%
18	Change in Regulatory Liabilities	269,133,676	36,517,739	636.99%
19	**Net Cash Provided by/(Used in) Operating Activities**	51,885,373	(10,194,566)	608.95%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(58,505,790)	(49,747,654)	-17.61%
22	(net of AFUDC & Capital Lease Related Acquisitions)			
23	Sale of Generation Assets	-	-	
24	Contributions In and Advances to Affiliates	-	(99,001,000)	-
25	Other Investing Activities:			
26	Miscellaneous Special Funds	(36,806)	473,237,760	-100.01%
27	**Net Cash Provided by/(Used in) Investing Activities**	(58,542,596)	324,489,106	-118.04%
28	**Cash Flows from Financing Activities:**			
29	Proceeds from Issuance of:			
30	Long-Term Debt	150,000,000	35,556,648	321.86%
31	Common Stock	467,115	2,445,313	-80.90%
32	Other: Manditorily Redeem. Pref. Securities of Sub. Trust			
33	Dividends from Subsidiaries	-	-	
34	Net Increase in Short-Term Debt	-	75,000,000	-
35	Other: Return of Subsidiary Capital			
36	Payment for Retirement of:			
37	Long-Term Debt	(64,297,988)	(297,868,964)	78.41%
38	Preferred Stock	-	-	-
39	Net Decrease in Short-Term Debt	(75,000,000)		
40	Dividends on Preferred Stock	(3,769,784)	(3,690,034)	-
41	Dividends on Common Stock	-	(62,426,418)	100.00%
42	Other Financing Activities (explained on attached page) 2/	-	(60,784,409)	100.00%
43	**Net Cash Provided by (Used in) Financing Activities**	7,399,343	(311,767,864)	102.37%
44				
45	**Net Increase/(Decrease) in Cash and Cash Equivalents**	742,120	2,526,676	-70.63%
46	**Cash and Cash Equivalents at Beginning of Year**	(4,538,779)	(7,065,455)	35.76%
47	**Cash and Cash Equivalents at End of Year**	($3,796,659)	($4,538,779)	16.35%
48				
49	1/ The cash balances on the 2001 and 2000 balance sheets include CMP, whereas the statement of			
50	cash flows does not.			
51				
52	2/ The amount listed on line 42 for 2000 is the amount paid to reacquire Common Stock.			

Sch. 24

LONG TERM DEBT 1/

Line	Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
1									
2	**First Mortgage Bonds**								
3	8.25% Series, Due 2007	12/05/91	02/01/07	55,000,000	54,550,100	364,966	8.260%	30,167	8.27%
4	8.95% Series, Due 2022	12/05/91	02/01/22	50,000,000	49,536,500	1,437,200	8.957%	129,979	9.04%
5	7.00% Series, Due 2005	03/01/93	03/01/05	50,000,000	49,375,000	5,370,355	7.075%	383,032	7.13%
6	7.30% Series, Due 2006	11/27/01	12/01/06	150,000,000	148,670,240	149,121,250	7.426%	11,324,552	7.59%
7	**Total First Mortgage Bonds**			$305,000,000	$302,131,840	$156,293,771		$11,867,730	7.59%
8									
9	**Pollution Control Bonds**								
10	6-1/8% Series, Due 2023	06/30/93	05/01/23	$90,205,000	$88,199,743	$88,771,073	5.841%	$5,620,635	6.33%
11	5.90% Series, Due 2023	12/30/93	12/01/23	80,000,000	79,040,800	79,294,183	6.428%	4,834,215	6.10%
12	**Total Pollution Control Bonds**			$170,205,000	$167,240,543	$168,065,256		$10,454,850	6.22%
13									
14	**Other Long Term Debt**								
15	Quarterly Income Preferred Securities,								
16	8.45%, Series A (QUIPS) 2/	11/96	11/01	$ 65,000,000	$ 62,567,385	$ 65,000,000		$ 5,553,304	8.54%
17	Medium Term Notes-Secured Series	Various	Various	128,000,000	126,807,269	28,000,000		2,076,332	7.42%
18	Medium Term Notes-Unsecured Series B	Various	Various	115,000,000	113,851,197	39,832,471		3,069,288	7.71%
19	Cost Associated with Prior Debt Retirements	N/A	N/A	0	0	0		201,237	N/A
20	**Total Other Long Term Debt**			$308,000,000	$303,225,851	$132,832,471		$10,900,161	8.21%
21	**TOTAL LONG TERM DEBT**			$783,205,000	$772,598,234	$457,191,498		$33,222,741	7.27%

1/ Total Long-Term Debt does not include ESOP debt of $12,666,000, as ESOP debt is not used for rate making purposes.
Total Long-Term Debt does not include amounts due within 1 year - $ 0 at December 31, 2001.

2/ The Company believes and intends to take the position that the securities associated with the QUIPS issue will constitute indebtedness for United States federal income tax purposes. As such, the cost of QUIPS are deemed to be tax deductible. Since November 6, 2001, the Company has the right to wholly redeem the securities at any time, or partially redeem them from time to time.

Sch. 25

PREFERRED STOCK

	Series	Issue Date	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embedded Cost %
1										
2	$6.00 Series Cumulative	1929-1932	159,589	$100	$110.000	$15,958,900	6.00%	$15,958,900	$957,534	6.00%
3										
4	$4.20 Series Cumulative	May 1954	60,000	$100	$103.000	6,024,600	4.18%	6,024,600	252,000	4.18%
5										
6	$6.875 Series Cumulative 1/	Nov 1993	360,800	$100	$103.438	35,670,412	6.88%	35,670,412	2,480,500	6.95%
7										
8										
9										
10	**TOTAL PREFERRED STOCK**		580,389			$57,653,912	6.36%	$57,653,912	$3,690,034	6.40%
11										
12	1/ Not redeemable prior to November 1, 2003, at which point call price will decrease by .344 per year to equal 100.00 at November 1, 2013.									

Sch. 26

COMMON STOCK

	Avg. Number of Shares Outstanding 1/	Book Value Per Share 2/	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price		Price/ Earnings Ratio
						High	Low	
January	103,743,534	$10.75				$26.50	$18.06	
February	103,755,534	10.90				22.22	17.55	
March	103,760,218	11.24	$0.58			18.20	13.05	
April	103,760,218	11.18				14.49	11.19	
May	103,773,500	11.22				16.75	12.75	
June	103,774,500	11.12	(0.11)			13.59	9.65	
July	103,774,500	11.09				11.48	9.45	
August	103,774,500	11.10				9.90	6.40	
September	103,774,500	10.87	(0.27)			7.15	5.07	
October	103,774,500	10.82				7.46	5.01	
November	103,774,500	10.79				5.40	3.95	
December	103,774,500	10.77	(0.09)			5.95	4.36	
TOTAL Year End	103,767,875	$10.77	$0.11	$0.00	100.00%	$5.75		52.3

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for 2001.

2/ All Book Value Per Share amounts are based on actual shares and include unallocated stock held by Trustee for the Deferred Savings and Employee Ownership Plans.

Sch. 27

MONTANA EARNED RATE OF RETURN - ELECTRIC

		Description	This Year	Last Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$1,130,070,071	$1,039,063,190	8.76%
3	108	Accumulated Depreciation	(402,143,778)	(351,411,120)	-14.44%
4					
5		**Net Plant in Service**	$727,926,293	$687,652,070	5.86%
6		Additions:			
7	154, 156	Materials & Supplies	$6,412,825	$7,437,251	-13.77%
8	165	Prepayments			0.00%
9		Other Additions 3/	48,988,710	120,593,479	-59.38%
10					
11		**Total Additions**	$55,401,535	$128,030,730	-56.73%
12		Deductions:			
13	190	Accumulated Deferred Income Taxes 1/	$130,112,342	$142,677,086	-8.81%
14	252	Customer Advances for Construction	16,946,982	14,704,355	15.25%
15	255	Accumulated Def. Investment Tax Credits	0	0	0.00%
16		Other Deductions 4/	18,241,383	13,338,485	36.76%
17					
18		**Total Deductions**	$165,300,707	$170,719,926	-3.17%
19		**Total Rate Base**	$618,027,121	$644,962,874	-4.18%
20		**Net Earnings**	($2,258,050)	$24,778,741	-109.11%
21		**Rate of Return on Average Rate Base**	-0.365%	3.842%	-109.51%
22		**Rate of Return on Average Equity 2/**	-12.737%	-3.391%	-275.61%
23					
24		**Major Normalizing and**			
25		**Commission Ratemaking Adjustments**			
26					
27		Rate Schedule Revenues	$594,975	$1,624,115	-63.37%
28		ASiMI Losses writeoff	86,175,594	0	
29		Capitalized regulatory assets	(7,169,830)	0	
30		Non-Allowables:			
31		Advertising	864,859	662,320	
32		Benefit Restoration Plan	980,473	332,469	
33		Dues, Contributions, Other	54,246	46,611	16.38%
34		Corporate Overhead	0	278,994	
35					
36		Associated Income Taxes	(32,100,937)	(1,159,768)	-2667.87%
37		**Total Adjustments**	$49,399,379	$1,784,741	2667.87%
38		**Revised Net Earnings**	$47,141,329	$26,563,482	77.47%
39		**Adjusted Rate of Return on Average Rate Base**	7.628%	4.119%	85.20%
40		**Adjusted Rate of Return on Average Equity 2/**	6.974%	-2.090%	433.68%

1/ Includes adjustments related to FAS 109.

2/ ROE calculation utilizes a average of four quarters common equity component applied to rate base for the denominator of the equations. The 2001 common equity component applied to rate base was 42.26%. An average was used to more accurately reflect 2001 common equity.

3/ Adjusted ROE includes $3,431,734 and $3,389,057 interest adjustment on excess proceeds from generation sale for 2001 and 2000 respectively.

Sch. 27 cont.

MONTANA EARNED RATE OF RETURN - ELECTRIC

	Description	Last Year	This Year	% Change
1				
2	**Detail - Other Additions 3/**			
3	FAS 109 Regulatory Asset	$42,232,476	$49,316,832	-14.36%
4	Conservation Expenditures	0	27,989,827	-100.00%
5	Cost of Refinancing Debt	2,284,219	3,398,428	-32.79%
6	Colstrip Unit 3 Carrying Charge	0	38,349,152	-100.00%
7	Corette PS&I	0	311,674	-100.00%
8	Fuel	0	145,336	-100.00%
9	Division Centralization	56,251	72,348	-22.25%
10	Qualifying Facilities Buyout	0	11,590	-100.00%
11	ORCOM Development Costs	853,687	0	100.00%
12	SAP Development Costs	2,823,844	0	100.00%
13	1999 Severance Plan	125,696	0	100.00%
14	1997 &1998 Severance Plan	125,653	0	100.00%
15	1995 & 1996 Severance Costs	486,884	622,866	-21.83%
16	1994 Severance Costs	0	375,426	-100.00%
17	**Total Other Additions**	$48,988,710	$120,593,479	-59.38%
18				
19	**Detail - Other Deductions 4/**			
20	Personal Injury and Property Damage	$2,135,840	$2,102,304	1.60%
21	Unamortized Gain on Reacquired Debt	17,766	26,987	-34.17%
22	Milltown Dam	3,920,342	0	100.00%
23	Bird Plant Reserve	1,164,218	0	100.00%
24	Gross Cash Requirements	5,574,447	6,021,372	-7.42%
25	Kerr Mitigation	0	0	
26	Storm Damage Reserve	669,263	879,912	-23.94%
20	Met Life Refund	144,724	0	100.00%
27	Materials & Supplies Non-Consumable Parts	0	9,668	-100.00%
27	USBC Expenses	4,614,783	4,298,242	7.36%
21	Net Kerr Mitigation	0	0	
22				
23	**Total Other Deductions**	$18,241,383	$13,338,485	36.76%

Sch. 28	MONTANA COMPOSITE STATISTICS - ELECTRIC (EXCLUDES UNIT 4 & YNP)		
		Description	Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	$ 1,143,823,680
5	105	Plant Held for Future Use	-
6	107	Construction Work in Progress	8,135,564
7	114	Plant Acquisition Adjustments	3,106,285
8	151-163	Materials & Supplies	$7,172,394
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	$411,780,157
11	252	Contributions in Aid of Construction	16,635,337
12	**NET BOOK COSTS**		733,822,429
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	475,913,425
17			
18	**Total Operating Revenues**		475,913,425
19			
20	401-402	Other Operating Expenses	410,377,838
21	403-407	Depreciation & Amortization Expenses	41,647,685
22	408.1	Taxes Other than Income Taxes	37,802,339
23	409-411	Federal & State Income Taxes	(11,656,385)
24			
25	**Total Operating Expenses**		478,171,477
26	**Net Operating Income**		(2,258,052)
27			
28	415-421.1	Other Income	1,131,021
29	421.2-426.5	Other Deductions	1,381,582
30	**NET INCOME BEFORE INTEREST EXPENSE**		(2,508,613)
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	237,429
34		Commercial & Industrial	52,232
35		Other	3,708
36			
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		293,369
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Kwh)	8,316
41		Average Annual Residential Cost per (Kwh)	$0.067
42		Average Residential Monthly Bill	$46.78
43			
44		Plant in Service (Gross) per Customer	$3,899

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,234	455	115	8	578
2	Alberton	374	336	77	22	435
3	Alder	116	184	61	18	263
4	Amsterdam	727			1	1
5	Anaconda	9,417	4,125	678	50	4,853
6	Armington		1			1
7	Arrow Creek		5	3		8
8	Augusta	284	232	88	7	327
9	Austin		1			1
10	Avon	124	91	53	2	146
11	Barber		50	9	2	61
12	Basin	255	157	64	2	223
13	Bearcreek-Washoe	83	66	16	4	86
14	Belfry	219	195	62	25	282
15	Belgrade	5,728	4,626	853	55	5,534
16	Belt	633	613	204	14	831
17	Benchland		7	7		14
18	Big Sandy	703	357	136	14	507
19	Big Sky	1,221	1,673	304	6	1,983
20	Big Timber	1,650	1,119	329	24	1,472
21	Bigfork	1,421				-
22	Billings	89,847	39,197	6,326	562	46,085
23	Black Eagle		433	100	3	536
24	Bonner	1,693	82	18	4	104
25	Boulder	1,300	722	204	38	964
26	Box Elder	794	122	72	8	202
27	Bozeman	27,509	18,046	3,345	170	21,561
28	Brady		98	37	8	143
29	Bridger	745	395	131	29	555
30	Broadview	150	205	142	8	355
31	Buffalo			3		3
32	Butte	33,892	13,971	2,106	322	16,399
33	Cameron		187	80	8	275
34	Canyon Creek		152	27	9	188
35	Carter	62	117	64	2	183
36	Cascade	819	953	233	21	1,207
37	Centerville		16	11	4	31
38	Checkerboard		57	13		70
39	Chester	871	494	263	26	783
40	Chinook	1,386	832	289	26	1,147
41	Choteau	1,781	953	341	43	1,337
42	Churchill		2			2
43	Clancy	1,406	1,420	207	2	1,629
44	Clinton	549	93	32	2	127
45	Coffee Creek		54	22		76
46	Colstrip	2,346	947	186	32	1,165
47	Columbus	1,748	922	285	22	1,229
48	Conrad	2,753	1,273	460	38	1,771
49	Corbin-Jefferson			1		1
50	Corvallis	443	610	136	56	802

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Craig		84	16	5	105
2	Custer	145		3		3
3	Darby	710	678	198	18	894
4	Deer Lodge	3,421	2,008	451	71	2,530
5	Denton	301	186	78	6	270
6	Dillon	3,752	1,819	483	71	2,373
7	Divide		54	9	4	67
8	Dodson	122	119	55	15	189
9	Drummond	318	348	195	36	579
10	Dutton	389	252	118	15	385
11	East Helena	1,642	2,370	307	22	2,699
12	Edgar		240	69	12	321
13	Elliston	225	195	62	4	261
14	Ennis	840	1,369	408	40	1,817
15	Fairfield	659	391	144	34	569
16	Florence	901	315	103	16	434
17	Floweree		108	57	1	166
18	Fort Belknap	1,262	20	13	1	34
19	Fort Benton	1,594	795	314	23	1,132
20	Fort Harrison		1	78	3	82
21	Fromberg	486	293	65	20	378
22	Galata			1		1
23	Gallatin Gateway		903	221	17	1,141
24	Gardiner	851	709	251	12	972
25	Garrison	112	105	54	5	164
26	Geraldine	284	279	141	7	427
27	Geyser		65	30	6	101
28	Gildford	185	92	68	9	169
29	Glasgow	3,253	1,725	569	89	2,383
30	Glen		2		2	4
31	Gold Creek		55	27	7	89
32	Gransdale		24	4	2	30
33	Great Falls	56,690	26,188	4,291	395	30,874
34	Greycliff	56	49	27	12	88
35	Hall		181	51	18	250
36	Hamilton	3,705	4,514	1,099	86	5,699
37	Hardin	3,384	1,411	412	53	1,876
38	Harlem	848	868	264	43	1,175
39	Harlowtown	1,062	651	250	22	923
40	Harrison	162	159	49	28	236
41	Haugan-Deborgia	69	197	63	1	261
42	Havre	10,594	4,889	998	250	6,137
43	Helena	45,819	19,305	3,815	340	23,460
44	Hingham	157	109	67	4	180
45	Hinsdale		140	44	11	195
46	Hobson	244	152	52	12	216
47	Huson		100	26	2	128
48	Inverness	103	47	26	2	75
49	Jardine			4		4
50	Jeffers		2	2		4
51	Jefferson City	295	208	34	3	245

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Joliet	575	354	83	21	458
2	Joplin	210	101	48	7	156
3	Judith Gap	164	92	39	4	135
4	Kremlin	126	73	40	2	115
5	Laurel	6,255	2,879	384	14	3,277
6	Lavina	209	178	83	11	272
7	Lennep-Ringling		60	41	3	104
8	Lewistown	5,813	3,209	811	79	4,099
9	Lincoln	1,100	972	198	3	1,173
10	Livingston	6,851	4,154	919	63	5,136
11	Logan		3	9	2	14
12	Lohman		22	18	7	47
13	Lolo	3,388	1,169	149	20	1,338
14	Loma	92	75	45	5	125
15	Lothair		15	9		24
16	Malta	2,120	1,325	419	68	1,812
17	Mammoth		162	66	2	230
18	Manhattan	1,396	1,504	288	105	1,897
19	Martinsdale		111	67	6	184
20	Marysville		53	25		78
21	Maxville		1			1
22	McAllister		121	27	4	152
23	Melrose		1		2	3
24	Melstone	136	158	298	14	470
25	Melville		81	46	1	128
26	Milltown		78	21		99
27	Missoula	57,053	28,510	4,989	452	33,951
28	Moccasin		46	29	5	80
29	Molt		17	16		33
30	Monarch		319	46		365
31	Moore	186	101	36	8	145
32	Musselshell	60	63	27	2	92
33	Nashua	325	206	59	10	275
34	Neihart	91	179	28	1	208
35	Norris		54	32	5	91
36	Nye		24	2		26
37	Old Faithful			1		1
38	Paradise	184	150	49	9	208
39	Park City	870	379	54	6	439
40	Philipsburg	914	1,511	234	19	1,764
41	Plains	1,126	1,291	357	37	1,685
42	Pony		118	21	4	143
43	Power	171	82	41	6	129
44	Pray		19	1	1	21
45	Radersburg	70	60	4		64
46	Ramsay		45	21	1	67
47	Raynesford		58	32	1	91
48	Red Lodge	2,177	1,635	343	37	2,015
49	Reedpoint	185	138	49	8	195

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Rocker		13	7		20
2	Rocvale		2			2
3	Roscoe		72	9		81
4	Roundup	1,931	1,094	390	25	1,509
5	Rudyard	275	159	65	7	231
6	Ryegate	268	140	61	11	212
7	Saco	224	156	83	9	248
8	Saint Marie	183	168	56	22	246
9	Salesia		28	5	1	34
10	Saltese		32	19	2	53
11	Sand Coulee		130	41	1	172
12	Sapphire Village		59	3		62
13	Shawmut		47	24	2	73
14	Sheridan	659	775	188	38	1,001
15	Silverbow		15	3	4	22
16	Springdale		35	16	7	58
17	Square Butte		42	24		66
18	St. Regis	315	384	133	14	531
19	Stanford	454	337	179	17	533
20	Stevensville	1,553	1,625	464	59	2,148
21	Stockett		166	43		209
22	Sumatra			3		3
23	Superior	893	751	250	16	1,017
24	Tampico			1		1
25	Thompson Falls	1,321	924	295	23	1,242
26	Three Forks	1,728	1,166	392	66	1,624
27	Tiber			4		4
28	Toston	105	49	52	26	127
29	Townsend	1,867	1,035	250	25	1,310
30	Tracy		99	13	1	113
31	Trident		2			2
32	Twin Bridges	400	304	136	33	473
33	Twodot		49	37	6	92
34	Ulm	750	358	108	6	472
35	Utica		2	4		6
36	Valier	498	360	174	30	564
37	Vaughn	701	221	37	3	261
38	Victor	859	705	221	25	951
39	Virginia City	130	141	79	4	224
40	Wagner		44	17	1	62
41	Warm Springs			2		2
42	White Sulphur Springs	984	760	303	44	1,107
43	Whitehall	1,044	912	234	58	1,204
44	Williamsburg		2	1		3
45	Willow Creek	209	132	48	17	197
46	Windham		52	27	2	81
47	Winston	73	86	25	4	115
48	Wolf Creek		389	125	4	518
49	Yellowstone Park		1	7		8
50	Zurich		104	62	11	177
51	**Total**	448,194	237,503	49,677	5,231	292,411
52						
53	1/ Customer populations represent an average of the 12 month period from 01/01/01 through 12/31/(					

Sch. 30	MONTANA EMPLOYEE COUNTS			
	Department	Year Beginning 1/	Year End 1/	Average
1				
2	**Utility Operations**			
3	Executive - 2/		3	
4	Financial, Risk Mgmt. & Information Services - 2/		98	49
5	Human Resources & Administration - 2/		38	19
6	Utility Services & Division Administration	706	665	686
7	Corporate Administration - 2/	140		70
8	Business Development & Regulatory Affairs	18	14	16
9	Transmission	214	188	201
10	Legal - 2/		8	
11	Generation	1		1
12	**Total Utility**	1,079	1,014	1,047
13				
14	**Other Corporate**			
15	Office of the Corporation			
16	**Total Other Corporate**	0	0	0
17	**TOTAL EMPLOYEES**	1,079	1,014	1,047
18				
19	1/ Part time employees have been converted to full time equivalents.			
20				
21	2/ The total number of employees is for The Montana Power Company only. In the past, a portion of			
22	The Montana Power Services Company employees were included in the total. During 2001,			
23	these employees became employees of the utility division of Montana Power.			
24				

Sch. 31	MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3			
4	Rainbow-Helena Tower Line Reconductoring	$1,926,600	$1,926,600
5	Hauser 69kV rebuild 10mi	1,100,000	1,100,000
6			
7			
8			
9	All Other Projects < $1 Million Each	37,199,483	37,199,483
10			
11	**Total Electric Utility Construction Budget**	40,226,083	40,226,083
12			
13	**Natural Gas Operations**		
14			
15	Telstad Compressor Station Upgrade	1,100,000	1,100,000
16	North Cobb 16" Loop Line	1,600,000	1,600,000
17			
18	All Other Projects < $1 Million Each	10,629,127	10,629,127
19			
20	**Total Natural Gas Utility Construction Budget**	13,329,127	13,329,127
21			
22	**Common**		
23			
24	All Other Projects < $1 Million Each	1,390,700	1,390,700
25	(Includes Milltown, SAS, AP, Reg Affairs, Carry over)		
26			
27			
28	**Total Common Utility Construction Budget**	1,390,700	1,390,700
29			
30	**Colstrip Unit 4**	1,800,000	1,800,000
31			
32			
33			
34			
35			
36	**Total Colstrip Unit 4 Construction Budget**	1,800,000	1,800,000
37	**TOTAL CONSTRUCTION BUDGET**	$56,745,910	$56,745,910

Sch. 32	TOTAL SYSTEM & MONTANA PEAK AND ENERGY					
		System Peak and Energy				
		Peak Day	Peak Hour	Peak Day Volume Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	January	17	1900	1,237	794,826	184,494
2	February	15	1900	1,270	730,954	179,866
3	March	1	800	1,155	695,744	159,135
4	April	1	800	1,155	602,621	115,012
5	May	24	1800	1,096	638,391	146,024
6	June	28	1700	1,165	672,290	152,969
7	July	11	1700	1,237	748,581	225,519
8	August	11	1700	1,290	708,323	150,770
9	September	4	1700	1,189	667,605	141,659
10	October	24	2000	1,033	604,922	148,559
11	November	26	1900	1,176	615,068	134,063
12	December	19	1900	1,252	745,838	133,568
13	**TOTALS**				8,225,163	1,871,638
14		Montana Peak and Energy				
15		Peak	Peak	Peak Day Volume	Total Monthly Volumes	Non-Requirements
16		Day	Hour	Megawatts	Energy (Mwh)	Sales For Resale (Mwh)
17	January					
18	February					
19	March					
20	April					
21	May					
22	June					
23	July			NOT AVAILABLE		
24	August					
25	September					
26	October					
27	November					
28	December					
29	**TOTALS**				-	-

Sch. 33	TOTAL SYSTEM SOURCES & DISPOSITION OF ENERGY			
	Sources	Megawatthours	Dispositions	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,611,276		
3	Nuclear	-	**Sales to Ultimate Consumers**	7,315,027
4	Hydro - Conventional	13,537	(Include Interdepartmental)	
5	Hydro - Pumped Storage	-		
6	Other	654	Sales for Resale	
7	(Less) Energy for Pumping	-	Requirement Sales	34,752
8	**Net Generation**	1,625,467	Non-Requirement Sales	1,871,638
9	**Purchases**	6,394,413	**Sales for Resale**	1,906,390
10	Power Exchanges		Energy Furnished w/o Charge	
11	Received	1,063,957		
12	Delivered	1,034,198		-
13	**Net Power Exchanges**	29,759	**Energy Furnished**	-
14	Transmission Wheeling for Others		Energy Used Within Utility	
15	Received	4,577,193	Electric Department	
16	Delivered	4,401,670	(Less) Station Use	-
17	**Net Transmission Wheeling**	175,523	**Net Energy Used Within Util.**	-
18	**Transmission by Others Losses**	-	**Energy Losses**	(996,255)
19	**TOTAL SOURCES**	8,225,162	**TOTAL DISPOSITIONS**	8,225,162

Sch. 34	SOURCES OF ELECTRIC SUPPLY /1				
	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Hydro	Milltown	Missoula, MT	2.5	13,537.9
2	Subtotal			2.5	13,537.9
3	Internal Combustion	Lake	Yellowstone Nat'l Park	0.0	130.1
4	Internal Combustion	Old Faithful	Yellowstone Nat'l Park	0.0	243.3
5	Internal Combustion	Tower Falls	Yellowstone Nat'l Park	0.0	7.2
6	Internal Combustion	Grant Village	Yellowstone Nat'l Park	0.0	273.4
7	Subtotal			0.0	654.0
8	Purchases	Small Power Producers	Colstrip Energy, Ltd.	0.0	314,857.0
9	Purchases	Small Power Producers	Billings Generation, Inc.	0.0	425,962.0
10	Purchases	Small Power Producers	State of Montana - DNRC	0.0	40,474.0
11	Purchases	Small Power Producers	Others	0.0	15,187.0
12					
13	Purchases	Nonassociated Utilities	Avista	0.0	1,296.0
14	Purchases	Nonassociated Utilities	Washington Water Power	0.0	508,700.0
15	Purchases	Nonassociated Utilities	PPL Montana	0.0	4,785,619.0
16					
17	Purchases	Cooperatives	Basin Electric Coop	0.0	17,232.0
18					
19	Purchases	Marketing Agencies	Avista Energy	0.0	145,629.0
20		Marketing Agencies	Enron Power Marketing	0.0	140,947.0
21	Purchases	Marketing Agencies	Montana Power Trading & Marketing	0.0	14,321.0
22	Subtotal			0.0	6,410,224.0
23	Total			2.5	6,424,415.9
24					
25	\1 An outage report does not accompany schedule 34 because of the sale of almost all of our generation assets				
26	in December 1999.				

Sch. 35	MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

NorthWestern Energy (NWE) submits an annual report on USB program activities, including conservation, market transformation, low-income and renewables, to the Montana Department of Revenue (DOR). The following pages are taken from the 2000 and 2001 reports, and are consistent with the way in which NWE has reported on USB programs since 1999. Additional programmatic information is available in the reports submitted by NWE to DOR.

	USB Categories		2001 Spent in 2001	Contracted - 2001 Complete - 2002	Total 2001 Funds
1–2	**USB Categories**		**2001 Spent in 2001**	**Contracted - 2001 Complete - 2002**	**Total 2001 Funds**
3	**Local Conservation**		$ 679,728	$ 980,673	**$ 1,660,401**
4	E+ Residential Audit/Sm. Com. Pilot		$ 420,767	$ 777,842	$ 1,198,609
5	E+ Business Partners		$ 42,585	$ 202,831	$ 245,416
6	MPLLC Promotion		$ 108,982	$ -	$ 108,982
7	MPLLC Labor		$ 79,678	$ -	$ 79,678
8	MPLLC Admin. Non-labor		$ 27,716	$ -	$ 27,716
9	Local Conservation Summary		$ 679,728	$ 980,673	$ 1,660,401
10	**Market Transformation**		$ 742,391	$ 109,860	**$ 852,251**
11	E+ Commercial Lighting		$ 155,566	$ 109,860	$ 265,426
12	NW Energy Efficiency Alliance		$ 456,989	$ -	$ 456,989
13	MPLLC Promotion		$ 41,673	$ -	$ 41,673
14	MPLLC Labor		$ 67,774	$ -	$ 67,774
15	MPLLC Admin. Non-labor		$ 20,389	$ -	$ 20,389
16	Market Transformation Summary		$ 742,391	$ 109,860	$ 852,251
17	**Renewable Resources**		$ 519,026	$ 594,519	**$ 1,113,545**
18	Generation/Education		$ 449,383	$ 594,519	$ 1,043,902
19	MPLLC Promotion		$ 2,795	$ -	$ 2,795
20	MPLLC Labor		$ 57,666	$ -	$ 57,666
21	MPLLC Admin. Non-labor		$ 9,182	$ -	$ 9,182
22	Renewable Resources Summary		$ 519,026	$ 594,519	$ 1,113,545
23	**Research & Development**		$ 64,328	$ -	**$ 64,328**
24	R&D/ Infrastructure		$ 34,084	$ -	$ 34,084
25	MPLLC Promotion		$ 12,561	$ -	$ 12,561
26	MPLLC Labor		$ 7,817	$ -	$ 7,817
27	MPLLC Admin. Non-labor		$ 9,866	$ -	$ 9,866
28	Research & Development Summary		$ 64,328	$ -	$ 64,328
29	**Low Income** (See Low-Income Category)		$ 1,610,875	$ 183,658	**$ 1,794,533**
30	Bill Assistance		$ 846,315	$ -	$ 846,315
31	Free Weatherization		$ 336,369	$ 119,658	$ 456,027
32	Energy Share		$ 253,006	$ -	$ 253,006
33	Renewables		$ 36,000	$ 64,000	$ 100,000
34	MPLLC Promotion		$ 93,852	$ -	$ 93,852
35	MPLLC Labor		$ 25,276	$ -	$ 25,276
36	MPLLC Admin. Non-labor		$ 20,056	$ -	$ 20,056
37	Low Income Summary		$ 1,610,875	$ 183,658	$ 1,794,533
38	**Irrigation**		$ 2,407	$ 243,623	**$ 246,030**
39	Irrigation Conservation		$ -	$ 243,623	$ 243,623
40	MPLLC Promotion		$ 284	$ -	$ 284
41	MPLLC Labor		$ -	$ -	$ -
42	MPLLC Admin. Non-labor		$ 2,123	$ -	$ 2,123
43	Renewable Resources Summary		$ 2,407	$ 243,623	$ 246,030
44	**Large Customer** *(d)*		$ 1,830,133	$ 639,774	**$ 2,469,907**
45	Self-Directed Energy Reduction		$ 1,775,475	$ 537,932	$ 2,313,406
46	*Self-Directed to Low Income*		$ 48,591	$ 5,809	$ 54,400
47	Unspent $ Reallocated by MPLLC	$ 102,100	$ -	$ -	$ -
48	-MPLLC Labor	$ 5,555	$ 5,555	$ -	$ 5,555
49	-MPLLC Admin. Non-labor	$ 513	$ 513	$ -	$ 513
50	*-Bill Assistance*	$ -	$ -	$ -	$ -
51	*-Free Weatherization*	$ 48,016	$ -	$ 48,016	$ 48,016
52	*-Energy Share*	$ 48,016	$ -	$ 48,016	$ 48,016
53	Large Customer Summary	$ 102,100	$ 1,830,133	$ 639,774	$ 2,469,907
54	**Totals**	**$ 102,100**	**$ 5,448,887**	**$ 2,752,107**	**$ 8,200,994**
55	**Total 2001 USB Funds**				**$ 8,200,994**
56					
57					

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MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

2001 USB EXPENDITURE SUMMARY

USB Category	Total Spent in 2001	Contracted - 2001 Complete - 2002	Total 2001 USB Funding	% of Total 2001 USB Funding	Total With MPLLC Reallocations *(b)*	% of Total 2001 USB Funding *(b)*	TOTAL 2001 By USB Category *(c)*	% of TOTAL 2001 USB Funding *(c)*
Local Conservation *(a)*	$ 679,728	$ 980,673	$ 1,660,401	20%	$ 1,660,401	20%	$ 1,660,401	20%
Market Transformation	$ 742,391	$ 109,860	$ 852,251	10%	$ 852,251	10%	$ 852,251	10%
Renewables	$ 519,026	$ 594,519	$ 1,113,545	14%	$ 1,113,545	14%	$ 1,113,545	14%
Research & Development	$ 64,328	$ -	$ 64,328	1%	$ 64,328	1%	$ 64,328	1%
Low Income	$ 1,610,875	$ 183,658	$ 1,794,533	22%	$ 1,890,565	23%	$ 1,944,965	24%
Irrigation	$ 2,407	$ 243,623	$ 246,030	3%	$ 246,030	3%	$ 246,030	3%
Large Customer *(d)*	$ 1,830,133	$ 639,774	$ 2,469,907	30%	$ 2,373,874	29%	$ 2,319,474	28%
	$ 5,448,887	**$ 2,752,107**	**$ 8,200,994**	**100%**	**$ 8,200,994**	**100%**	**$ 8,200,994**	**100%**

2001 ENERGY SAVINGS & RENEWABLE RESOURCES SUMMARY

	Projects Completed with 2001 USB $			Projects To Complete in 2002 w/ 2001 USB $		
USB Category	aMW	MWH	MW	aMW	MWH	MW
Local Conservation	0.2856	2,502	0.428	0.5124	4,489	1.037
Market Transformation *(1)*	2.6480	23,197	0.587	0.1993	1,746	0.395
Renewables *(2)*	0.0370	324	0.075	0.4480	3,924	1.160
Research & Development	NA	NA	NA	NA	NA	NA
Low Income	0.0406	356	0.130	0.0172	151	0.060
Large Cust - Low Income	NA	NA	NA	0.0057	50	0.018
Large Customer *(3)*	NA	NA	NA	NA	NA	NA
	3.011	**26379**	**1.220**	**1.183**	**10360**	**2.670**

	aMW	MWH	MW
Total 2001 USB Energy Savings & Renewable Resources:	**4.194**	**36,739**	**3.890**

2001 LOW-INCOME FUNDING SUMMARY

Low-Income Category	
Bill Assistance	$ 846,315
Free Weatherization *(b)*	$ 504,044
Energy Share *(b)*	$ 301,022
Low-Income Renewables	$ 100,000
	$ -
MPLLC Promotion	$ 93,852
MPLLC Labor	$ 25,276
MPLLC Admin. Non-labor	$ 20,056
Large Customer Dollars Self-Directed to Low-Income Activities *(d)*	$ 54,400
TOTAL Low-Income USB Funding :	**$ 1,944,965**

23.7% of 2001 USB Funds collected were directed to Low-Income

2001 CUSTOMER / PROJECT SUMMARY

USB Category	Customers / Projects *(4)*
Local Conservation	5,496
Market Transformation	2,787
Renewables	17
Research & Development	NA
Low Income	10,141
Large Customer	NA
	18,442

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

(a) 2001 Renewable category funds allocated include $500,000 toward a renewable wind generation project planned to come on line in the future. DOR granted extension of funding for this project.

(b) These columns show the reallocation by MPLLC of unspent 2001 Large Customer USB dollars to low-income activities [see *(d)*]. MPLLC reallocated $96,032 unspent Large Customer funds to low-income activities per PSC Order D97.7.90 Order 5986i, and with advice of the MPLLC USB Advisory Committee, dividing the amount equally between Free Weatherization and Energy Share -- $48,016 for each activity.

(c) These columns show the TOTAL allocated to each public purpose category. The Low Income total includes (b) and $54,400 Large Customer self-directed to Low Income funds. The Large Customer total shows only the Large Customer self-directed to non-low income purposes and the MPLLC costs associated with administering Large Customer USB activities.

(d) Large Customers may self-direct their USB dollars to energy saving and renewable activities in their qualified facilities, or may self-direct their USB dollars to low-income activities. Large customers report their activities separate of Montana Power's report. A total of $102,100 unspent Large Customer funds were reallocated by MPLLC in 2001. $6,068 was re-directed to offset MPLLC's Large Customer USB administration costs, and $96,032 was reallocated to low-income purposes [see *(b)*].

(1) Market Transformation includes conservation resource estimates provided by the Northwest Energy Efficiency Alliance. MPLLC has adjusted some measures reported by the Alliance to account for natural gas space and water heating. The Alliance also performs research and development for market transformation for which no energy savings are quantified, but contribute to the transformation of the marketplace for energy efficiency.

(2) Renewable resource numbers include 1 MW associated with project funds allocated from 2001 planned to come on line in the future. The DOR granted extension of funding for this project.

(3) Large customer resource numbers for are reported by individual large customers and are not availble in this report.

(4) The 2001 Customer/Project Summary counts energy-saving and renewable projects for individual customers, projects which affect more than one customer, and the number of customers reached through efforts like the MPLLC Low-Income Discount, which does not provide energy-savings or renewable resources, but serves a significant number of MPLLC customers. The number of MPLLC customers served by Northwest Energy Efficiency Alliance include commercial projects and customers purchasing Energy Star washers, dishwashers, and refrigerators. The Alliance also reported the sale of 275,590 Energy Star compact fluorescent lamps and 91,174 square feet of Energy Star-rated windows installed in MPLLC's service territory.

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MONTANA CONSUMPTION AND REVENUES - ELECTRIC (EXCLUDES UNIT 4 & YNP)

	Operating Revenues		MWH Sold		Average Customers	
	Current Year	Previous Year	Current Year	Previous Year 2/	Current Year	Previous Year
Sales of Electricity						
Residential	$133,278,079	$128,288,474	1,974,529	1,985,295	237,429	235,785
Commercial & Industrial	204,103,936	206,810,913	5,274,634	5,765,551	52,232	51,366
Public Street, Highway Lighting & Other Sales to Public Authorities 1/	9,006,654	6,907,178	41,817	39,198	3,704	3,656
Sales to Cooperatives	699,491	9,042,724	34,752	278,669	1	55
Sales to Other Utilities	61,797,754	65,831,927	325,188	658,669	3	6
Interdepartmental	746,589	771,982	-	-	-	-
TOTAL SALES	$409,632,503	$417,653,198	7,650,920	8,727,382	293,369	290,868

1/ The customer classes "Public Street" and "Highway Lighting" are combined with "Other Sales to Public Authorities" in our customer accounting system.

2/ Prior year MWH sold has been adjusted to remove Colstrip Unit 4 sales from "Sales to Other Utilities" and to reclass irrigation from "Public Street, Highway Lighting & Other Sales to Public Authorities" to "Commercial & Industrial".